Note:

The data and information contained in the L.R. 455 Final Report Appendix is intended to supplement the research and discussion presented in the Final Report. This material should not be read or interpreted outside of the context of the report.

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Table 1-1 NEBRASKA MUNICIPAL SYSTEMS FORMED PRIOR TO 1900

1887—City of Crete	1887—Village of Prague
1888—Village of Panama	1889—City of West Point
1890—City of Tecumseh	1890—Village of Snyder
1890—City of Falls City	1892—City of Schuyler
1894—Village of Fremont	1896—City of South Sioux City
1897—City of Wayne	

Table 1-2 NEBRASKA MUNICIPAL SYSTEMS FORMED 1900—1910
[18 of the municipal systems on record formed during this period]

1900—Village of Fairmont	1900—Village of Morrill
1900—City of Wilber	1901—City of Hastings
1905—City of Grand Island	1905—City of Friend
1905—Village of Hampton	1905—Village of Trenton
1905—City of Wisner	1906—Village of Polk
1908—City of Wahoo	1909—City of Central City
1909—City of Cambridge	1910—City of Blue Hill
1910—Village of Campbell	1910—City of Fairbury
1910—City of Franklin	1910—City of Plainview

CHAPTER TWO APPENDIX SECTION

Introduction

Consumer demographics have major impacts on the costs to serve individual consumers and the rates ultimately charged to the consumer. Two common demographic measurements, consumer density and consumer mix, can be useful in determining why there are differences between utilities in the costs to serve their consumers.

Consumer Density

Consumer density can be measured in terms of consumers per mile of line, consumers per circuit mile of line or consumers per square mile. High consumer density allows a utility to invest less in their utility plant facilities on a per consumer basis than a utility with a low consumer density. This lower investment provides an opportunity for lower rates because there are less costs to recover on a per consumer basis. Customer density differences impact primarily the delivery function of costs to serve customers.

The NPA LR455 Survey indicated that consumer density averaged over 50 consumers per mile of line for medium and large municipal systems. Those same municipals indicated consumers per square mile served averaged over 300. There was insufficient data for the smaller municipal systems of the NPA LR455 Survey to derive similar statistics. Little national data is available for comparison.

The results of a nationwide survey of 844 rural electric cooperatives and power districts conducted by the National Rural Utilities Cooperative Finance Corporation indicated that the average rural power provider served 5.16 consumers per mile of line in 1995. NPA Survey of the Nebraska rural electric system indicated significantly different results of 2.40 and 2.22 consumers per mile and per square mile, respectively. Nebraska's rural electric system's consumers per mile of line are 47% of the national average of rural electric systems and only about 4% of average Nebraska medium and large municipal systems.

Consumer Mix

Consumer load requirements and service needs require various pricing methods for certain classifications of consumers. Typically, an electric utility will break down consumer classifications into those categories with similar load characteristics and similar costs to serve. The major classifications in Nebraska, as well as in the utility industry in general, consist of residential, commercial, and industrial consumers. Nebraska utilities also segregate irrigation consumers due to the significant amount of load from this class of consumer. This additional class of consumer is not generally segregated into national electric utility surveys.

Residential consumers make up the majority of the class of consumers served by Nebraska utilities representing approximately 82% of consumers served. Commercial consumers represent approximately 13% of consumers while industrial, irrigation and other consumers comprise the last 5%.

In terms of energy sales and revenues, residential consumers contribute approximately 40% of all sales and revenues, commercial consumers contribute approximately 30%, industrials contribute approximately 20% and irrigation and other consumers contribute the balance.

Per the NPA LR455 Survey[1], statewide Nebraska electric utilities consist of 71% urban and 29% rural consumers. The consumers' revenue and energy usage breaks down as follows:

TABLE 1

STATE OF NEBRASKA						
RETAIL						
Class of Consumers	No. of Consumers	% of Consumers	Energy (MWH)	% of Sales	Revenues ($1,000)	% of Revenues
Residential	687,214	82.2	7,564,902	37.0	$482,306	43.5
Commercial	105,847	12.7	6,648,369	32.5	$339,276	30.6
Industrial	2,368	0.3	4,775,113	23.4	$188,115	16.9
Irrigation	31,569	3.8	749,624	3.7	$61,504	5.5
Other	8,907	1.0	692,219	3.4	$39,049	3.5
TOTAL	**835,905**	**100.0**	**20,430,227**	**100.0**	**$1,110,250**	**100.0**

The NPA Survey data does not match Department of Energy (DOE)[2] data for the State of Nebraska due primarily to different reporting by OPPD in the commercial and industrial

[1]NPA LR455 Survey, December 1996.

[2]Electric Power Annual 1995 Volume II, December 1996 DOE/EIA-0348(95)/2

sectors.[3] In addition, the NPA Survey data may not necessarily be 100% complete, but it includes key breakdowns not available from the DOE source, in particular irrigation statistics.

National consumer data is reported by the Department of Energy (DOE)[2]. In 1995, 3,200 electric utilities submitted their information to the DOE. The following national consumer information was extracted as follows:

TABLE 2

Class of Consumer	% of Consumers	% of Energy Sales	% of Revenue
Residential	87.8	34.6	42.2
Commercial	10.9	28.6	32.0
Industrial	0.5	33.6	22.7
Irrigation	*	*	*
Other	0.8	3.2	3.1

* National information was not available for irrigation consumers by separately. Irrigation consumers were included with the "other" category for the respondents in the DOE's survey.

Nebraska compares similarly in the residential area with the rest of the nation, however, the state consumer base is heavier in the commercial area, but less in the industrial area compared to the nation as a whole. This statistical information tends to imply that Nebraska relies more on commercial than the nation as a whole and less on the large industrial consumers. In addition, it is evident that irrigation consumers are more prevalent in Nebraska compared to other states.

An additional table is presented which disaggregates Statewide usage information into summaries for the Rural Electric Systems and the remainder of Nebraska. The NPA Survey obtained information from various sizes of municipals and power districts. The customer demographis of all sizes and types of systems were nearly the same except for Rural Electric

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[3]The Omaha Public Power District (OPPD) does not account for energy sales and revenue by commercial and industrial classifications. Instead, OPPOD uses small and large general service as its classifications for DOE/EIA 861 reporting. Small general service is defined as those customers with annual peak demands less than 1,000 kW. Large general service represents all customers with annual peak demands greater than 1,000 kW.

OPPD is in the process of adding and verifying the standard industrial classifications for each of its commercial and industrial customers with the intention of reporting energy sales and revenue to reflect commercial and industrial classifications in the future. The survey data prepared for the NPA LR455 Survey in December 1996 reflects OPPD sales and revenue information based on their best estimate of commercial and industrial information and is much more representative of commercial and industrial customers than the small and large classifications used for DOE/EIA reporting.

The 1995 DOE/EIA Form 861 data for Nebraska shows the following for retail sales and revenues: Residential (7,597 GWH and $484,060,000), Commercial (5,986 GWH and $332,561,000), Industrial (5,802 GWH and $222,881,000), Other (1,508 GWH and $88,369,000), and All Sectors (20,892 GWH and $1,127,871,000).

Systems. Rural Electric Systems represent almost 20% of the Nebraska consumers and 16% of the energy requirements. Tables 3 and 4 show the customers, retail sales and revenue for the Rural and Urban Systems.

One major difference is in the average usage per customer. Commercial and industrial consumers in the rural area use is only 46% and 70% respectively, of the average commercial and industrial consumer in the urban area. This is significant considering the average urban commercial uses 67,200 kWh per year and the average industrial consumer uses 2,115,700 kWh. The commercial establishments in the urban areas are supporting a greater number of people and therefore are larger in size than commercial facilities in the rural areas. In addition, larger industrial facilities are more likely to be located near population centers and major rail and transportation facilities to attract a work force and to ship their products.

However, the residential consumers of the Rural Systems have usage 36% higher than the urban consumer. This can be explained by the higher saturation of electric heat in the rural areas and farmstead/ranch usage of electricity involves other equipment and facilities supporting the farming/ranching enterprise.

Another significant difference is in the number of irrigation customers. Eighteen percent of rural consumers are irrigation customers whereas less than 1% of the urban customers are classified as irrigators.

TABLE 3

RURAL SYSTEMS						
RETAIL						
Class of Consumers	**No. of Consumers**	**% of Consumers**	**Energy (MWH)**	**% of Sales**	**Revenues ($1,000)**	**% of Revenues**
Residential	118,245	72.9	1,671,513	49.8	$103,864	49.2
Commercial	12,796	7.9	399,309	12.0	$24,174	11.5
Industrial	373	0.2	554,208	16.5	$23,892	11.3
Irrigation	29,163	18.0	707,255	21.1	$57,752	27.3
Other	1,615	1.0	21,674	0.6	$1,581	0.7
TOTAL	162,192	100.0	3,353,959	100.0	$211,263	100.0

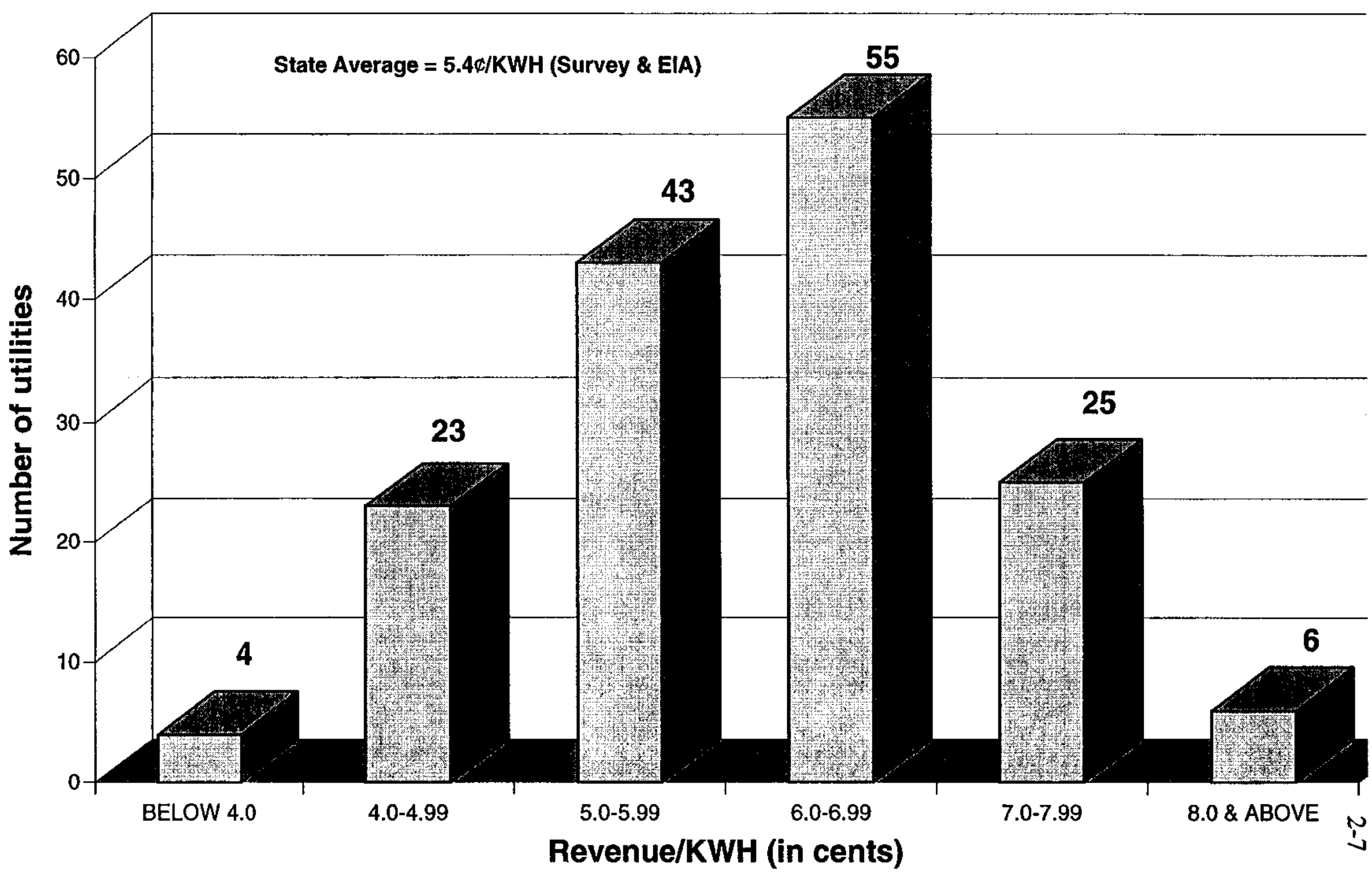
TABLE 4

URBAN SYSTEMS						
RETAIL						
Class of Consumers	**No. of Consumers**	**% of Consumers**	**Energy (MWH)**	**% of Sales**	**Revenues ($1,000)**	**% of Revenues**
Residential	568,969	84.4	5,893,389	34.6	$378,442	42.0
Commercial	93,051	13.8	6,249,060	36.6	$315,102	35.1
Industrial	1,995	0.3	4,220,905	24.7	$164,223	18.3
Irrigation	2,406	0.4	42,369	0.2	$3,752	0.4
Other	7,292	1.1	670,545	3.9	$37,468	4.2
TOTAL	673,713	100.0	17,076,268	100.0	$898,987	100.0

AVERAGE REVENUE PER KWH 1995

All Nebraska Electric Utilities

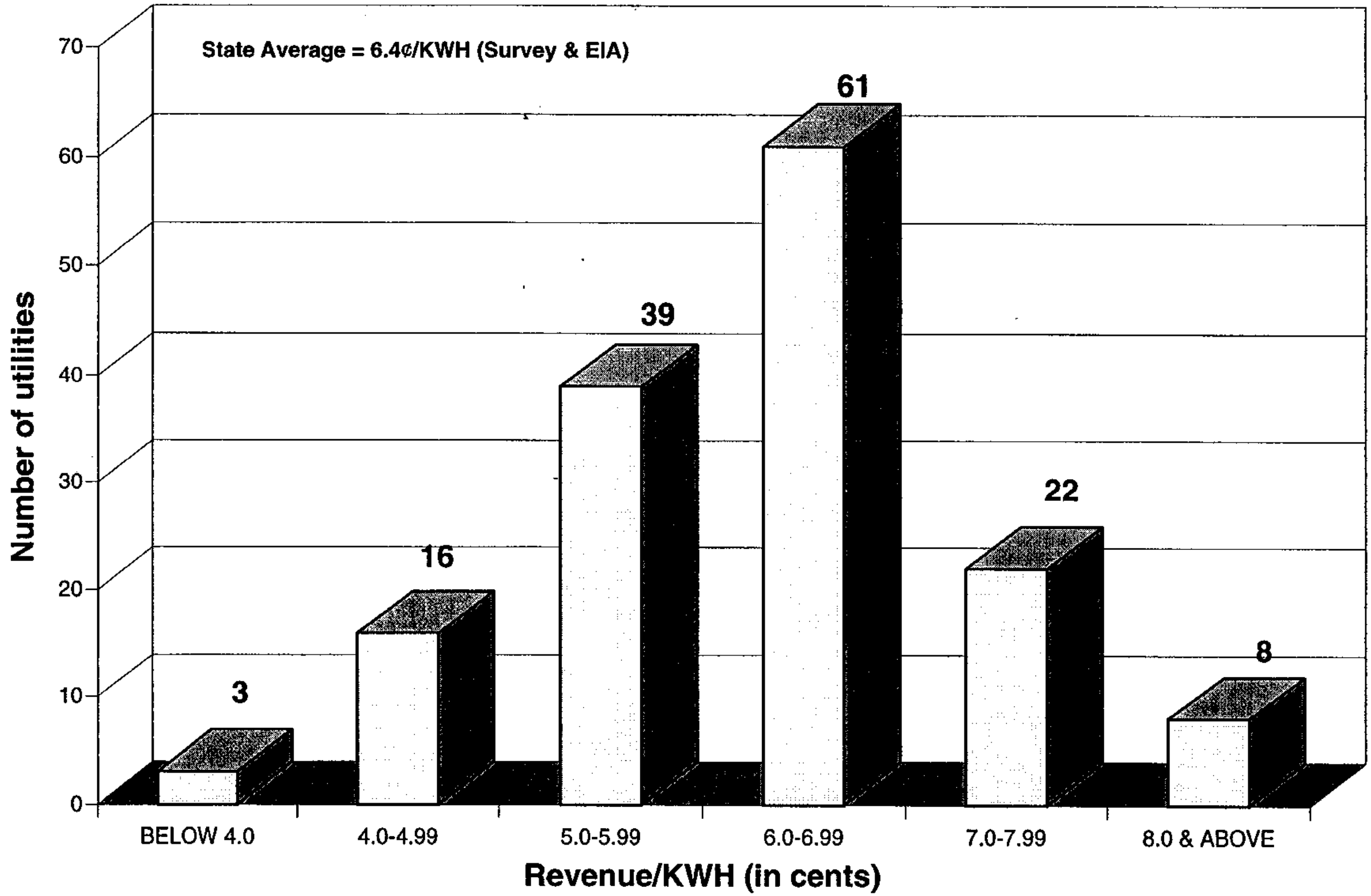
All Classes



SOURCE: ENERGY INFORMATION ADMINISTRATION
FORM 861

AVERAGE RESIDENTIAL REVENUE PER KWH 1995

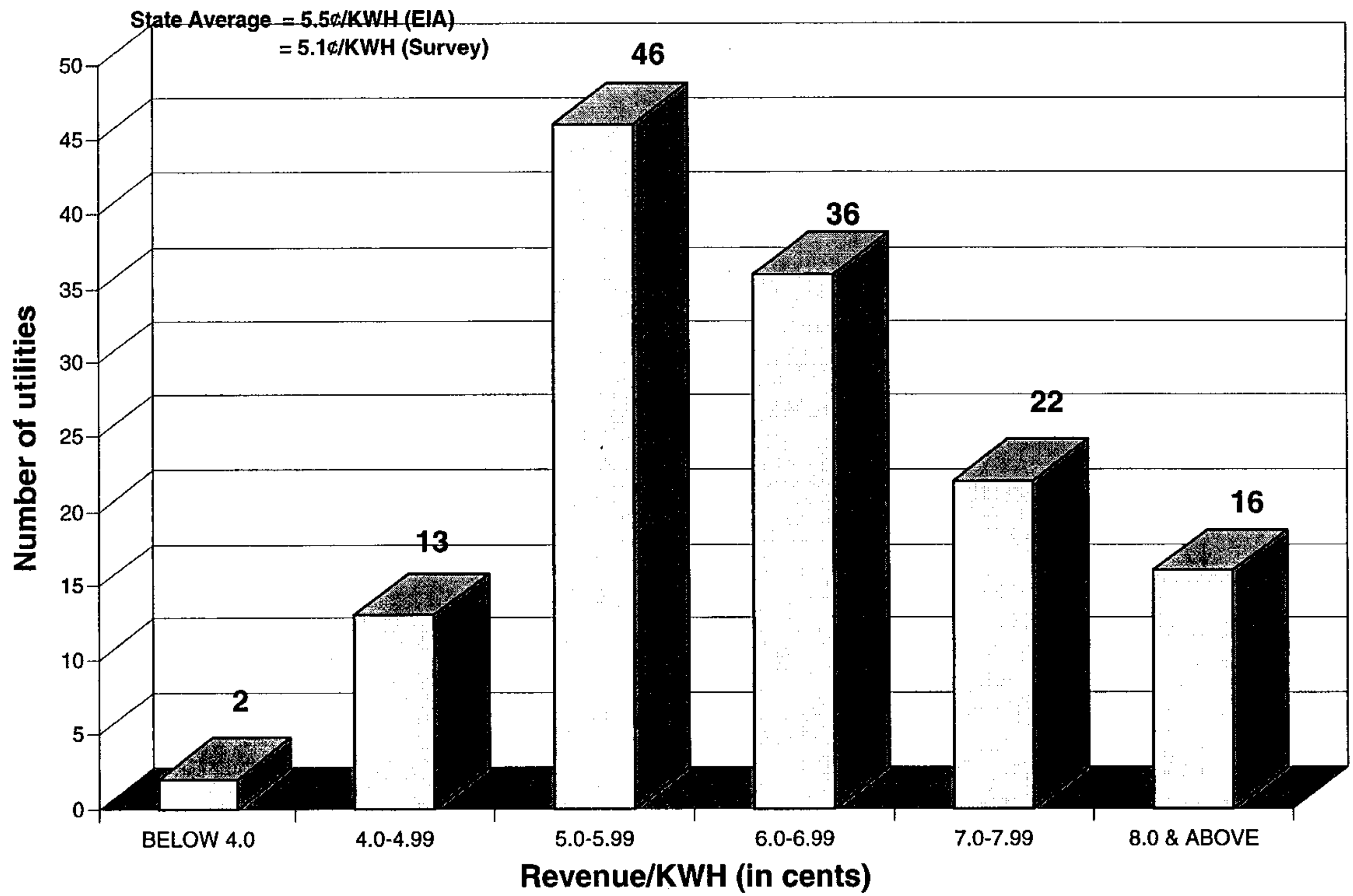
All Nebraska Electric Utilities



SOURCE: ENERGY INFORMATION ADMINISTRATION
FORM 861

AVERAGE COMMERCIAL REVENUE PER KWH 1995

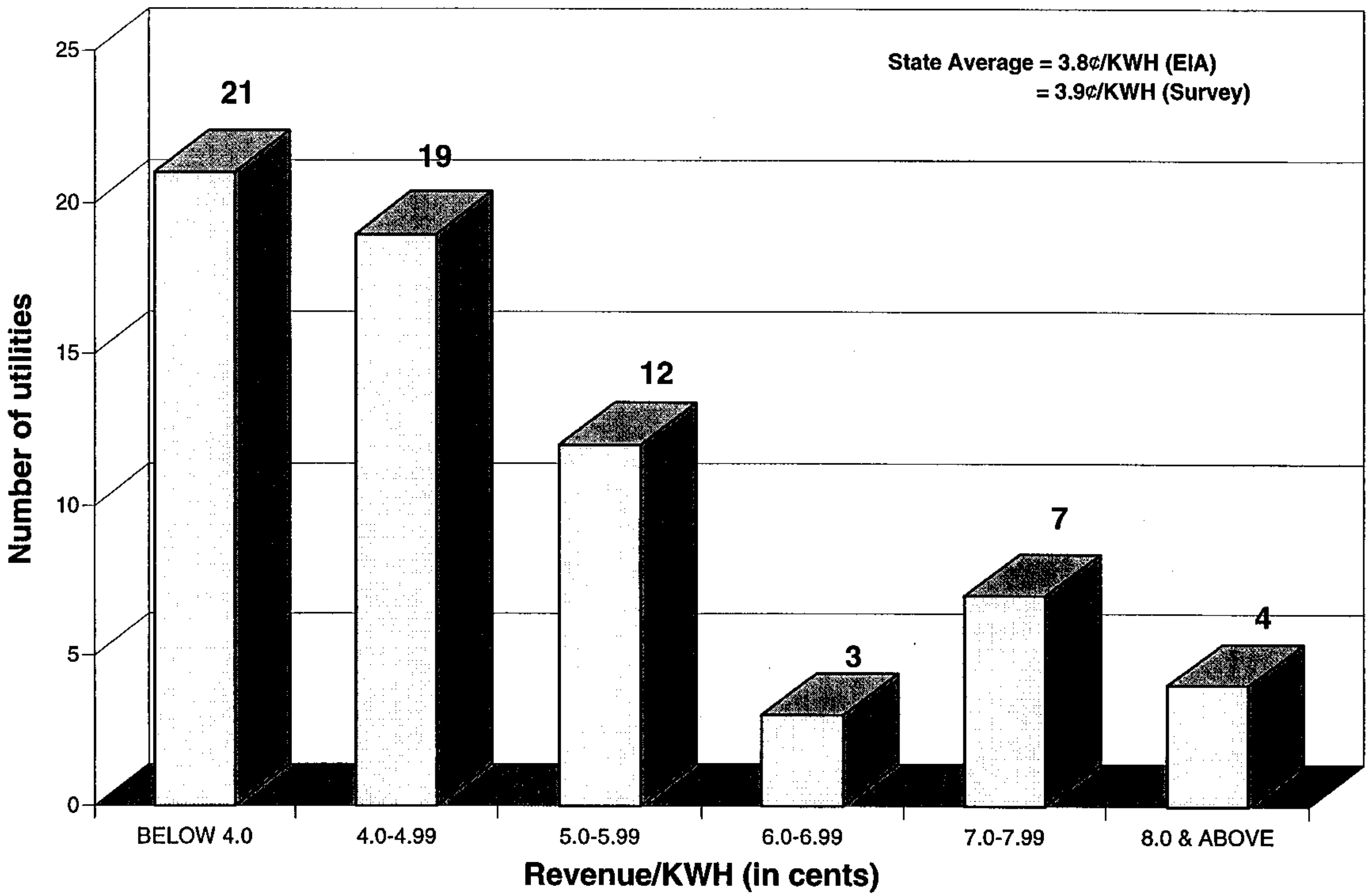
All Nebraska Electric Utilities



SOURCE: ENERGY INFORMATION ADMINISTRATION
FORM 861

AVERAGE INDUSTRIAL REVENUE PER KWH 1995

All Nebraska Electric Utilities



SOURCE: ENERGY INFORMATION ADMINISTRATION
FORM 861

Appendix 1
Comparison of Nebraska Utilities' Electric Bills [1]
January 1995

Customer	State Average		Utilities Serving Metro Areas [8] [11]	Smaller Communities [9]	Rural [10]
Residential 500 kWh	$ 38	(2)	$ 33	$ 37	$ 42
Residential 1000 kWh	$ 65	(2)	$ 59	$ 64	$ 69
Residential 3000 kWh	$ 133	(3)	$ 107	$ 107	$ 149
C&I 30 kW and 6,000 kWh	$ 355	(3)	$ 312	$ 336	$ 369
C&I 500 kW and 200,000 kWh	$ 9,182	(4)	$ 8,834	$ 8,013	$ 9,733
C&I 5,000 kW and 2,500,000 kWh	$ 92,248	(5)	$ 92,100	$ 85,620	$ 97,580
C&I 10,000 kW and 5,000,000 kWh	$ 181,605	(6)	$ 185,632	$ 174,938	$ 186,930
C&I 20,000 kW and 10,000,000 kWh	$ 334,288	(7)	$ 394,850	$ 297,304	$ 336,969

(1) NPA LR 455 Task Force Survey, December 1996

(2) Includes 3 power districts, l large municipality, 15 medium-sized municipals, 102 smaller communities, 28 rural power districts, and 3 cooperatives in the State Average.

(3) Same as (2) except 102 smaller communities not included in the State Average.

(4) Same as (3) except only 12 medium sized municipals in the State Average.

(5) Includes 3 power districts, 1 larger municipality, 6 medium-sized municipals, and 10 rural power districts in the State Average.

(6) Includes 3 power districts, 1 large municipality, 4 medium-sized municipals, and 6 rural power districts in the State Average.

(7) Includes 3 power districts and 5 rural power districts in the State Average.

(8) Includes 1 power district and 1 large municipal in the averages.

(9) Excludes 1 power district, 1 large municipal, the rural power districts & cooperatives, and exclusions identified in Notes 3 through 6 in the averages.

(10) Review Notes 2 through 6 regarding utilities in the State Average to determine the number of Rurals represented in the Rural average.

(11) Includes only 1 large power district in the average for the 20,000 kW customer.

Appendix 2
Comparison of Nebraska Utilities' Electric Bills [1]
July 1995

Customer	State Average		Utilities Serving Metro Areas [8] [11]	Smaller Communities [9]	Rural [10]
Residential 500 kWh	$ 39	(2)	$ 41	$ 37	$ 45
Residential 1000 kWh	$ 64	(2)	$ 77	$ 61	$ 75
Residential 3000 kWh	$ 177	(3)	$ 213	$ 160	$ 184
C&I 30 kW and 6,000 kWh	$ 396	(3)	$ 380	$ 376	$ 409
C&I 500 kW and 200,000 kWh	$ 10,049	(4)	$ 10,070	$ 8,610	$ 10,651
C&I 5,000 kW and 2,500,000 kWh	$ 107,974	(5)	$ 103,799	$ 95,686	$ 118,640
C&I 10,000 kW and 5,000,000 kWh	$ 209,730	(6)	$ 185,030	$ 200,863	$ 226,830
C&I 20,000 kW and 10,000,000 kWh	$ 426,633	(7)	$ 375,162	$ 410,852	$ 443,240

(1) NPA LR 455 Task Force Survey, December 1996

(2) Includes 3 power districts, I large municipality, 15 medium-sized municipals, 102 smaller communities, 28 rural power districts, and 3 cooperatives in the State Average.

(3) Same as (2) except 102 smaller communities not included in the State Average.

(4) Same as (3) except only 12 medium sized municipals included in State Average.

(5) Includes 3 power districts, 1 larger municipality, 6 medium-sized municipals, and 10 rural power districts in the State Average.

(6) Includes 3 power districts, 1 large municipality, 4 medium-sized municipals, and 6 rural power districts in the State Average.

(7) Includes 3 power districts and 5 rural power districts in the State Average.

(8) Includes 1 power district and 1 large municipal in the averages.

(9) Excludes 1 power district, 1 large municipal, the rural power districts & cooperatives, and exclusions identified in Notes 3 through 6 in the averages.

(10) Review Notes 2 through 6 regarding utilities in the State Average to determine the number of Rurals represented in the Rural average.

(11) Includes only 1 large power district in the average for the 20,000 kW customer.

Appendix 3
Comparison of Electric Bills
January 1995
National Information

Customer	National Average		Utilities Serving Metro Areas	Smaller Communities
Residential 500 kWh	$ 44	(1)	$ 44	$ 46
Residential 1000 kWh	$ 82	(1)	$ 81	$ 88
Residential 3000 kWh	$ 229	(2)	Not Available	Not Available
C&I 30 kW and 6,000 kWh	$ 533	(2)	Not Available	Not Available
C&I 500 kW and 200,000 kWh	$ 12,399	(1)	$ 12,162	$ 13,957
C&I 5,000 kW and 2,500,000 kWh	$ 132,544	(1)	$ 128,998	$ 155,846
C&I 10,000 kW and 5,000,000 kWh	$ 260,738	(2)	Not Available	Not Available
C&I 20,000 kW and 10,000,000 kWh	$ 519,722	(2)	Not Available	Not Available

(1) KPMG Peat Marwick LLP, *National Electric Rate Survey - January 1, 1995*, Lincoln, Nebraska office, published June, 1995.

(2) EEI Publication, *Typical Residential, Commercial and Industrial Bill Investor-Owned Utilites, Winter 1995*, Bills as of January 1, 1995.

Appendix 4
Comparison of Electric Bills
July 1995
National Information

Customer	National Average		Utilities Serving Metro Areas	Smaller Communities
Residential 500 kWh	$ 45	[1]	$ 45	$ 46
Residential 1000 kWh	$ 87	[1]	$ 87	$ 90
Residential 3,000 kWh	$ 250	[2]	Not Available	Not Available
C&I 30 kW and 6,000 kWh	$ 563	[2]	Not Available	Not Available
C&I 500 kW and 200,000 kWh	$ 13,265	[1]	$ 13,269	$ 13,237
C&I 5,000 kW and 2,500,000 kWh	$ 141,899	[1]	$ 140,669	$ 149,985
C&I 10,000 kW and 5,000,000 kWh	$ 274,810	[2]	Not Available	Not Available
C&I 20,000 kW and 10,000,000 kWh	$ 547,714	[2]	Not Available	Not Available

[1] Lincoln Electric System, *National Electric Rate Survey - Summer 1995 for rates in* effect July 1, 1995, unpublished, Lincoln, Nebraska.
[2] EEI Publication, *Typical Residential, Commercial and Industrial Bill Investor-Owned Utility Summer 1995, bill as of July 1, 1995.*

Appendix 5
Comparison of Electric Bills
January 1995
Regional Information [1]

Customer	Regional Average	
Residential 500 kWh	$ 41	(2)
Residential 1000 kWh	$ 73	(2)
Residential 3000 kWh	$ 213	(3)
C&I 30 kW and 6,000 kWh	$ 517	(3)'
C&I 500 kW and 200,000 kWh	$ 10,586	(2)
C&I 5,000 kW and 2,500,000 kWh	$ 112,553	(2)
C&I 10,000 kW and 5,000,000 kWh	$ 233,981	(3)
C&I 20,000 kW and 10,000,000 kWh	$ 453,285	(3)

(1) Regional cities include Denver, Chicago, Indianapolis, Des Moines, Wichita, Kansas City, Mo, Minneapolis, and St. Louis.

(2) KPMG Peat Marwick LLP, *National Electric Rate Survey - January 1, 1995,* Lincoln, Nebraska office, published June 1995

(3) EEI Publication, *Typical Residential, Commercial and Industrial Bill Investor-Owned Utilites, Winter 1995, bills as of January 1, 1995*

Appendix 6
Comparison of Electric Bills
July 1995
Regional Information [1]

Customer	Regional Average	
Residential 500 kWh	$ 45	[2]
Residential 1000 kWh	$ 84	[2]
Residential 3000 kWh	$ 258	[3]
C&I 30 kW and 6,000 kWh	$ 578	[3]
C&I 500 kW and 200,000 kWh	$ 11,885	[2]
C&I 5,000 kW and 2,500,000 kWh	$ 123,703	[2]
C&I 10,000 kW and 5,000,000 kWh	$ 266,001	[3]
C&I 20,000 kW and 10,000,000 kWh	$ 512,891	[3]

[1] Regional cities include Denver, Chicago, Indianapolis, Des Moines, Wichita, Kansas City, Mo, Minneapolis, and St. Louis.

[2] Lincoln Electric System, *National Electric Rate Survey - Summer 1995 for rates in effect 7/1/95*, Lincoln, Nebraska, un-published.

[3] EEI Publication, *Typical Residential, Commercial and Industrial Bill Investor-Owned Utility, Summer 1995, bill as of July 1, 1995.*

Appendix 7
Comparison of Nebraska Energy Costs [1]
Cents per kWh
1995

Customer Class	State Average [2]	Utilities Serving Metro Areas [3]	Smaller Communities [4]	Rural [5]
Residential	6.4	6.6	6.2	6.2
Commercial	5.1	4.7	5.8	6.1
Industrial	3.9	4.0	3.8	4.3
Irrigation	8.2	11.1	8.0	8.2
Other	5.7	5.9	5.3	7.3
Total	5.4	5.3	5.3	6.3

(1) NPA LR 455 Task Force Survey, December 1996

(2) Represents 3 power districts, 1 large municipality, 16 medium-sized municipalities, 102 small communities, 28 rural power districts, and 3 cooperatives.

(3) Represents 1 power district and 1 large municipality serving areas greater than 100,000 population.

(4) Represents 2 power districts, 16 medium-sized municipalities, and 102 smaller communities.

(5) Represents 28 rural power districts and 3 cooperatives.

NOTE: The State average in the commercial and industrial sectors (5.1¢/kWh and 3.9¢/kWh) differs from the DOE/EIA Form 861 statistics due to reporting format changes by OPPD in the NPA survey data. See customer demographics section for a detailed explanation. Also, Irrigation is not a separate entry in the DOE/EIA Form 861 data.

Appendix 8
Comparison of Energy Costs
Cents per kWh
National and Regional Information

Customer Class	National Average [1]	National Rural CFC [2]	Regional Average [4]	Regional Rural CFC [5]
Residential	8.4	7.6	7.5	7.4
Commercial	7.7	[3]	6.2	6.6
Industrial	4.7	[3]	4.3	4.6
Irrigation		[3]		8.6
Other	6.9	[3]	6.9	5.9
Total	6.9	7.3	6.1	6.9

[1] Form EIA - 861, "*Annual Electric Report, 1995.*"

[2] National Rural Utility Cooperative Finance Corporation 1995 Annual Report.

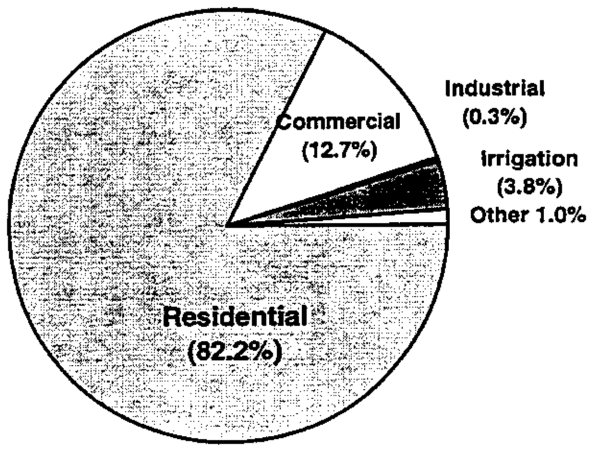
[3] Information was not reported by these classes. The average for non-residential classes combined is 6.8 cents/kWh.

[4] EIA, "Electric Power Annual," 1995, Volume II. Regional includes states adjacent to Nebraska but does not include Nebraska.

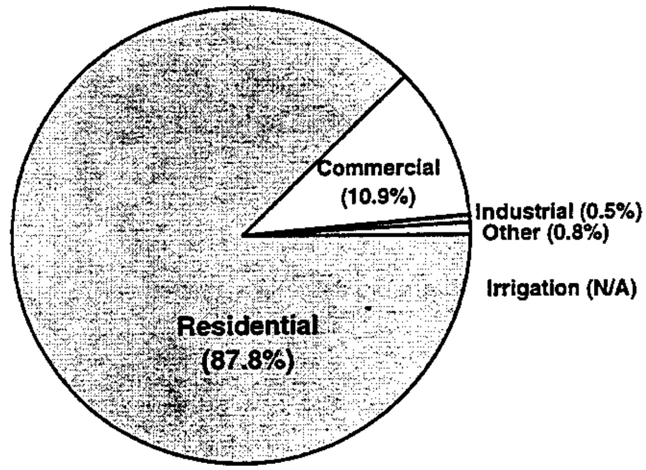
[5] National Rural Utility Cooperative Finance Corporation, Special Request on Regional States adjacent to Nebraska.

RETAIL CONSUMERS

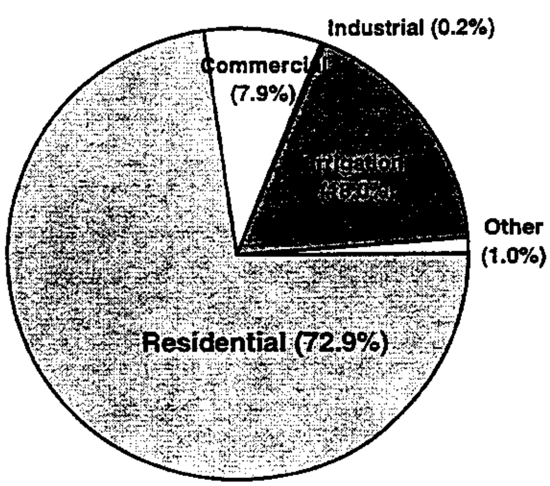
STATE OF NEBRASKA



NATIONAL



RURAL SYSTEMS



URBAN SYSTEMS

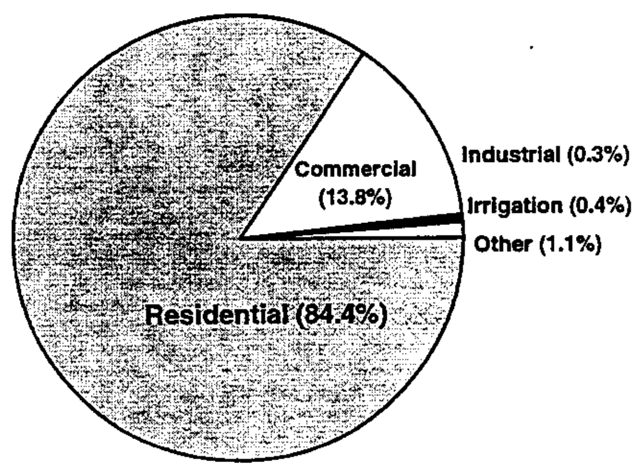
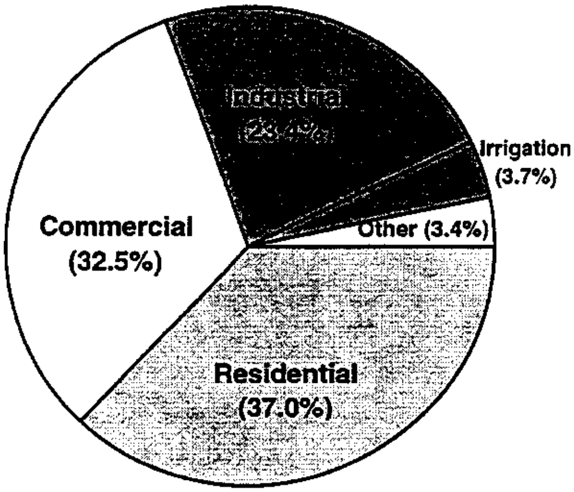


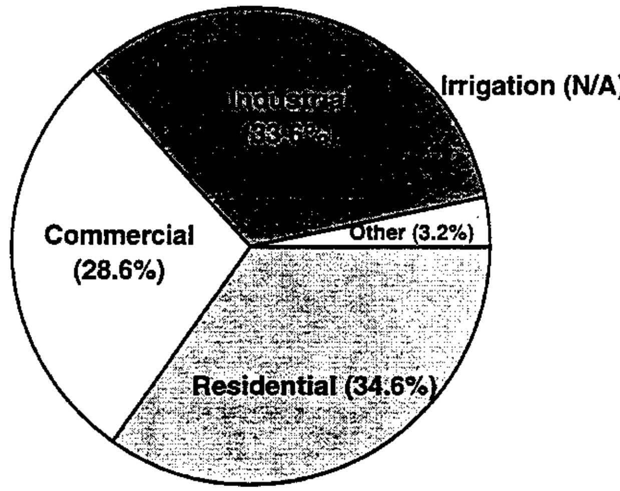
CHART 2

RETAIL ENERGY SALES

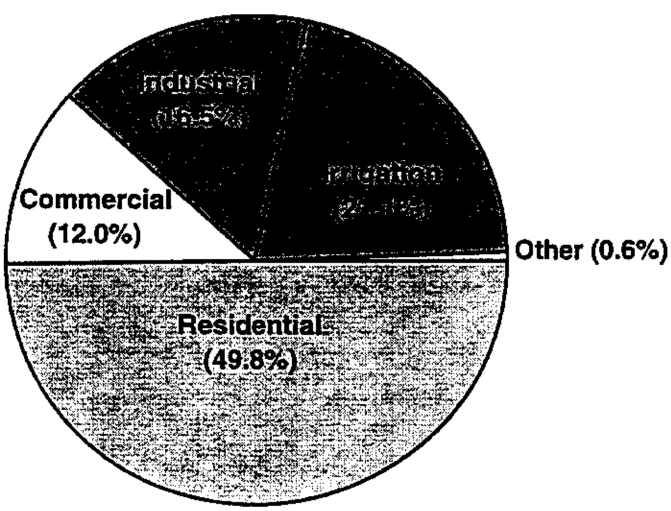
STATE OF NEBRASKA



NATIONAL RETAIL



RURAL SYSTEMS



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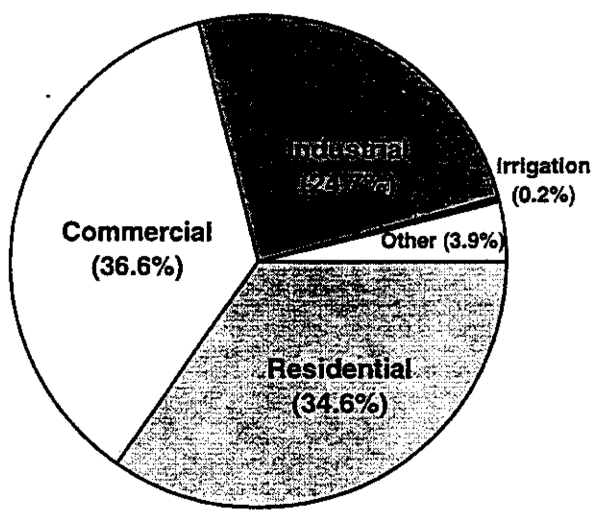
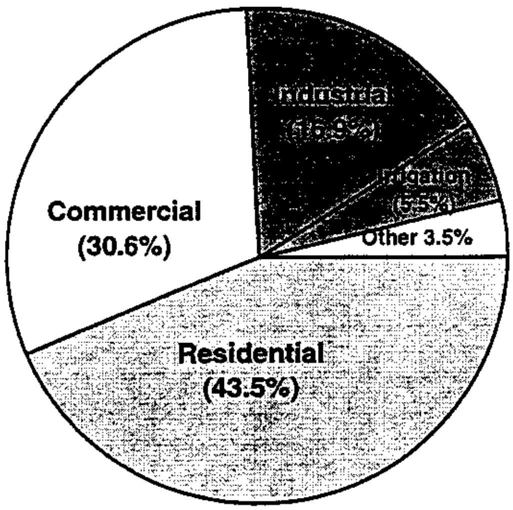


CHART 3

RETAIL REVENUES

STATE OF NEBRASKA



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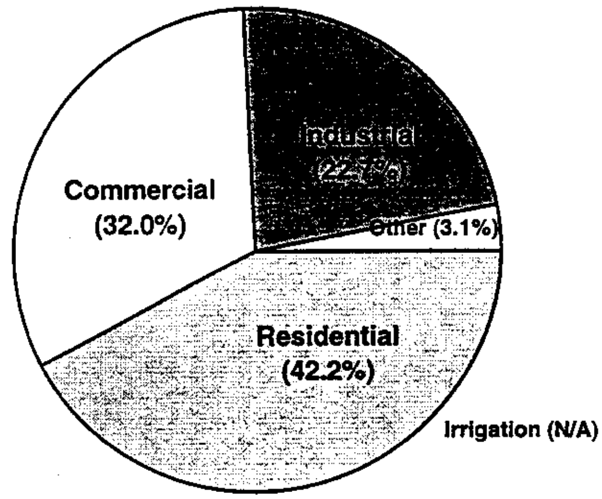
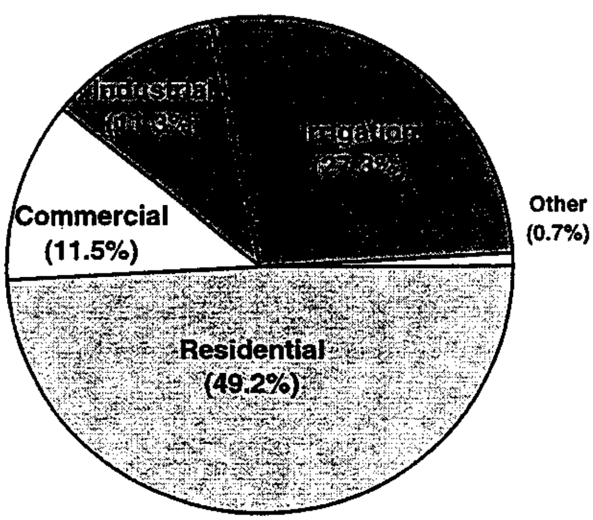
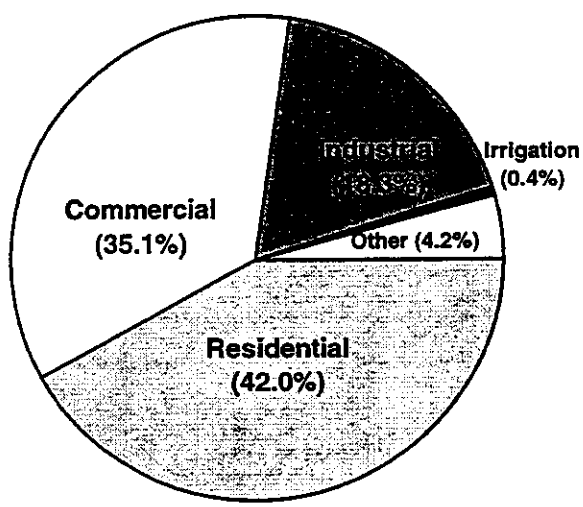


RURAL SYSTEMS



URBAN SYSTEMS



COST OF SERVICE RATEMAKING IN NEBRASKA

Nebraska utilities through policies adopted by their Boards of Directors or City Councils embrace the Cost of Service principle for ratemaking. The largest utilities conduct full Cost of Service studies on an ongoing basis typically annually. The smaller utilities will employ the assistance of consultants or utilize the expertise of a power pool, power association and will conduct Cost of Service studies on an as needed basis typically driven by the need to finance expansions or replacements.

All of the utilities currently use the traditional accounting cost-based Cost of Service Study. This is often referred to as the fully distributed embedded cost method and is contrasted with studies based on marginal cost that are used by a few utilities across the nation and other industries particularly those that are nonregulated.

Below is a brief discussion of the principles behind and the information utilized in accounting cost studies. That applies not only to studies conducted in Nebraska but by and large across the nation.

The basic principle behind developing rates based on accounting costs is that rates should recover expected costs in the 12-month period, referred to as test year, for which the rates are to apply. Regulated utilities in many states require the test year to be a previous 12-month period but allow adjustments to reflect cost and revenue changes anticipated during the upcoming year or to eliminate any unusual or nonrecurring costs that occurred during the test year.

Accounting cost or embedded cost studies reflect investments already made or to be made by the end of the test year. In contrast, marginal cost studies focus on the estimated costs of the facilities expected to be added to serve additional load or additional customers.

With respect to operating costs, such as the cost of fuel or purchased power, accounting costs include an average of total costs for the period being studied. In contrast, marginal cost studies give more attention to the change in costs which may result from providing an increment of service, such as an additional kilowatt-hour of energy.

Since actual costs form only the foundation for the accounting costs study, they may be adjusted in order to reflect changed conditions, to correct for unusual events in the period, or to include cost estimates expected in the period for which the rates are to apply.

Steps in The Ratemaking Process

STEP 1	Determine the revenue requirement of the utility.	Revenue Requirement Determination
STEP 2	Separate the costs by function (production, transmission, distribution, etc.)	Cost Allocation
STEP 3	Classify the costs (demand costs, energy costs, customer costs, etc.)	
STEP 4	Allocate the costs among customer classes and determine the revenue to be derived from each rate class.	
STEP 5	Design the rates (recognizing costs and other ratemaking considerations).	Rate Design

The five steps cover three general phases of development and approvals. The first is the determination of the revenue requirement based on a selected test year. Some utilities have their revenue requirements approved by their rate authority under a separate process such as a fiscal budget year approval while others may have a revenue requirements approved for one or more years including the approval of the cost allocation method and the final rate design in one approval process. For many utilities the cost allocation methodology has been in place for a number of years and undergoes only minor changes from study to study. The rate design phase includes the determination of rate structural forms to be used. Again, many of the structural forms have been in place for many years and additions and deletions are made as necessary in the approval of individual rate adjustments year to year.

Sources of Data

The principal items required to develop accounting cost studies are:

- Plant investment data - Utility Plant in Service, (UPIS) and Construction Work in Progress, (CWIP).
- Balance Sheet of Asset and Liabilities and Equity.
- Operating expenses from budgets or financial reports.
- Billing information (kW and kWh), number of accounts and revenues by rate class.
- Load research information (statistically selected accounts with hourly interval recorded usage, appliance saturations, housing and business types, etc.).

STEP 1 Revenue Requirements Determination

The test year Revenue Requirement is the amount required to operate in an efficient and reliable manner and provide service to customers at a "reasonable" price. The financial requirements include the obvious operating costs, such as fuel, purchased power, and salaries. There are also financial requirements related to investments in utility plant.

Revenue requirements associated with utility plant investment include the debt service requirements (interest and principal payments) on the borrowings and also debt service coverage adders. These are required by bond ordinances or covenants for most Nebraska utilities. Some also have minimum annual renewals and replacement bond covenant requirements that can force higher revenue requirements from time to time.

The type of test year used is governed by historical practices of the utility, requirements of the regulatory body or by changing characteristics including unusual load growth, planned plant additions and expected cost changes. If costs and sales are changing relatively slowly, the use of a historical test year is appropriate. However, the fully projected test year is particularly useful when the future conditions, such as costs, plant investment and loads, are expected to differ substantially from those of the recorded period. Some Nebraska utilities use a two-year test period.

<u>The Cost Allocation Procedure (Steps 2-4)</u>

It is generally accepted in the industry that cost is the single most important item in the development of regulated rates. Cost allocation studies provide the necessary information to keep rates reasonably close to cost and to monitor variations from study to study. Cost allocation is the process of taking the total revenue requirement of the utility and spreading it over various classes of customers (or rate categories) in a fashion which reflects the costs of providing service to each class. The cost allocation step may be bypassed if the present rates are based on a fairly recent cost allocation study and the staff believes that small adjustments will maintain rates that reasonably reflect cost of service. The rate changes then typically consist of uniform percentage adjustments applied to the existing rate components.

The cost of allocation process consists of three major parts, as follows:

<u>STEP 2</u> <u>Functionalization of Costs</u> - costs are separated according to distinctive functional categories to facilitate the allocation of these amount to rate classes consistent with the causation of costs by these classes. While the number of functional categories used may vary, the major cost functions for an electric utility are:

- Production or Purchased Power
- Transmission/Subtransmission
- Distribution
- Customer Service

<u>STEP 3</u> <u>Classification of Costs</u>

The next step is to separate the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs which vary with the kW demand imposed by the customer), energy costs (costs which vary with the energy or kWh which the utility provides), and customer costs (costs which are related to the number of customers served). In addition, some costs are designated as "specific assignments" if the costs can logically be directly assigned to a certain customer or class of customers. For example, the costs related to a radial transmission or distribution line serving only a particular customer may be assigned directly to that customer or to that class of customers. As another example, the costs of street lights can be directly assigned to the street light customer class, typically a city or county government.

Typical cost classifications used in cost allocation studies are summarized in the following table.

Typical Cost Functions	**Typical Cost Classifications**
Production and/or Purchased Power:	Demand Related Energy Related
Transmission: Subtransmission:	Demand Related Specific Assignments
Distribution:	Demand Related Customer Related Specific Assignments
Customer Service:	Customer Related

The typical cost classifications shown above reflect the following types of assumptions regarding cost causation for electric utilities:

- Production. Costs which are based on the generating capacity of the plant, such as depreciation, debt service, debt service coverage, or return on investment are demand-related costs. Some costs, such as cost of fuel and certain operation and maintenance expenses, are directly related to the quantity of energy produced. In the case of purchased power, demand charges are normally assumed to be demand related and energy charges are normally assumed to be energy related.

- Transmission and Subtransmission. The costs of transmission and subtransmission are fixed costs which do not vary with the quantity of energy transmitted, unless tied to an energy provision in a contract for Transmission Services. In some instances, the costs of certain facilities can logically be assigned directly to certain accounts or customer classes.

- Distribution. The costs of electric distribution systems are affected by demands and by the number of customers, but are not affected by energy quantities. In many cases, the costs of some distribution facilities can be specifically assigned to certain customers or classes who are the only beneficiaries of the facilities.

- Customer Service. These costs are related to the number of meters served, bills rendered, and general customer services such as technical assistance and information distribution.

Although cost classifications are often based on considerations similar to those listed above, there are numerous instances in which other methods of cost classification are used. For example, if a utility analyzes two generating alternatives and decides to build the plant with the higher capital cost per kilowatt of capacity in order to achieve the benefits of lower fuel costs per kilowatt-hour of generation, a portion of the fixed costs of the selected generating plant may be considered to be energy related.

STEP 4 Allocation of Costs Among Rate Classes

After the costs have been functionalized and classified, the next step is to allocate the costs among the rate classes. To accomplish this, the accounts served by the utility are separated into several groups based on the nature of the service provided and load characteristics. The four principal customer classes are: **Residential, Commercial, Industrial and Other.**

These are often subdivided based on characteristics such as size of load, the voltage level at which the customer is served, and other service characteristics such as whether a residential customer heats with electric equipment (all-electric) or not.

The **Other** classification typically includes street lighting, municipal pumping, and irrigation pumping. Once the customer classes have been established, the functionalized and classified costs are allocated among the classes as summarized below.

- Demand-Related Costs. These are costs incurred as a result of maximum power requirements and are allocated among the rate classes on the basis of demands (kW) imposed on the system. The utility has installed facilities such as generating stations and transmission lines to serve demands (or has contracted for services from other agencies). Measuring system demand is not merely a summation of individual customer account maximum demands. This is because individual account maximum demands (often referred to as billing demands) occur at different times of the day; at times not coincident with system peak hour. It is the maximum of the hourly demand summations that result in the system peak demand. In other words, the contribution of each account's individual demand at the hour the system achieves its peak determines its responsibility to the system Coincident Peak demand (CP). It is necessary to consider not only the maximum Demands of individual accounts, but also the aggregate rate class demands, one coincident with the system peak hour and one representing the maximum sum of the group's contribution to the class peak hour (i.e., as if the class were considered a mini-system).

  As a result, the demand component is often expressed or discussed in the following three terms:

  (1) System Peak Demand (CP). Contributions coincident with the system peak hour, this measurement is used to allocate costs such as those of production, particularly peaking resources, and bulk transmission plant.

(2) Class Noncoincident Peak (CNCP). This is the maximum demand of a homogenous group of accounts, e.g. a residential rate class. The hour of occurrence may or may not be the same as the system peak hour. It is often used to allocate local facility costs such as those of substation and primary distribution facilities.

(3) Customer Billing Demand (CBD). This is the highest kW measurement of an individual account. It is often used to allocate costs of secondary voltage distribution lines and line transformers.

CP and CNCP are determined on the basis of individual account contributions to either the system or class peaks. Classes of service (rate classes) are established, usually based on similar load levels and similar daily or monthly usage characteristics. These usage characteristics are studied in load research programs that use statistical sampling techniques to obtain information from special hourly interval recording meters.

Energy-Related Costs. These are costs allocated among the rate classes on the basis of energy (kWh) which the system must supply to serve the customers.

Customer-Related Costs. These are costs allocated among the rate classes on the basis of the number of customers or the "weighted" number of customers. Normally, the customers in the various classes are assigned weights based on an analysis of the relative levels of customer-related costs per customer. The analysis of customer costs reflects items such as: the costs of service lines, meters, meter reading, billing, customer accounting and collecting. When the weighting factors are developed, the residential customers are normally given a weight of 1.0. For example, a study may show the relative weights that reflect cost differences among classes are 1.0 for residential customers, 3 for commercial customers, and 10 for industrial customers.

Specific Assignments. These costs are assigned directly to a certain customer or class of customers. They are usually easily attributable to the particular customer or class of customers by the function or specific service provided (e.g., street lighting).

STEP 5 Rate Design

The final step is to determine per unit cost for energy ($/kWh), demand ($/kW) and customer services ($/bill or $/meter or $/facility used). These are determined by dividing cost components by test year billing units and may be presented as single monthly averages or in the form of cost curves reflecting varying usage levels and load factors. This information is used as a guide in the preparation of trial rate designs that are adjusted to balance the impacts on individual customers and total rate classes. Even though embedded cost is the primary basis for Nebraska utility studies marginal cot considerations are used to support certain aspects of rate design. For example marginal cost are used to determine interruptible load credits, off peak energy charges for heating and avoided cost payments for energy purchased from customer owned generation. The objective is to arrive at a proposed set of rates that recovers the proper amount of revenue allocated to each class without undue subsidization or billing shocks to classes of customers or to individual customers within each class. A series of adjustments over several years may be used to move rates closer to cost of service instead of imposing a single large adjustment on a class or usage level.

INDIVIDUAL RATE COMPONENTS TERMS AND CONDITIONS

Introduction

Nebraska utilities' rate schedules, terms and conditions for electric service have some or all of the following components as defined below. An Electric Rate Schedule is the charge methodology determined from costs utilized to recover adequate revenue from the consumer or class of consumers for the electricity or energy services provided. Terms and Conditions are the provisions necessary for serving and billing the consumer.

INDIVIDUAL RATE COMPONENTS

Ancillary Services

Those transmission and generation services required to maintain a reliable and efficient electrical system grid. The Federal Energy Regulatory Commission has identified six ancillary services that must be made available and applied to transactions involving wholesale wheeling. These services are described as follows:

Energy Imbalance Service

Services that correct for variances occurring between the hourly scheduled and hourly metered amounts of energy in a transaction.

Reactive Supply and Voltage Control Service

The proper operation of generation and transmission facilities to ensure that transmission voltages of the transmission supplier are within predetermined limits.

Regulation and Frequency Response Service

The increase or decrease of generation (predominantly through automatic means) to match moment-to-moment load changes.

Scheduling, System Control, and Dispatch Service

The control room procedure to establish before-the-fact use of generating resources and transmission facilities to meet anticipated load, including accounting for these services.

Spinning Reserve Service

Service that is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output.

Supplemental Reserve Service

Service that is needed to serve load in the event of a system contingency, however, it is not available immediately to serve load but rather within a short period of time, typically 10 minutes.

Backup Charges

Amount paid to a utility by consumers who normally generate all or part of their load requirements through a permanent connection with the utility. The amount paid is based on the costs incurred by the utility to backup the consumer in the event that the consumer's equipment fails or is out of service for maintenance.

Billing and Facilities Charges (Customer Charge)

An amount paid periodically (normally monthly) by a consumer for electric service based upon costs incurred for metering, meter reading, billing and other costs specifically incurred to provide service to that consumer.

Curtailable Electric Service Programs and Load Management Rates and Clauses

Programs which are designed to reduce a utility's peak load requirements by offering consumers rate discounts when service is interrupted during the utility's peak demand period. Most utility programs are targeted at large commercial, industrial and irrigation customers who pledge a minimum interruptible load level to be curtailed as directed by the utility during peak demand periods.

Demand Charges

That portion of the charge for electric service based on the maximum load requirement placed on the electric system. The maximum load requirement is metered and averaged over a set time interval and represents the amount of energy consumed in a billing interval. Typical demand billing intervals are 15 minutes, 30 minutes, and 60 minutes and vary by utility.

Demand Ratchet Clauses

The utility's equipment must be in place to serve the maximum demand of the consumer when the consumer requires it. The demand ratchet enables the utility to recover the cost of equipment or wholesale power costs required to serve the maximum demand if the demand varies considerably from month to month or season to season. The cost to serve utility consumers are calculated as an annual amount and collected over a 12 month period. The demand ratchet allows utilities to fairly allocate and collect these annual costs from a consumer. Consumers who have a high demand during the summer peak season and have low demands during the winter season are not unfairly subsidized by other consumers.

Energy Charges

That portion of the charge for electric service based on the amount of electric energy (kWh) consumed by the consumer.

Facility Standby Charge

Available to consumers electing to decline electric service from the utility during a period of time, typically one year. Rather than having the service disconnected and the distribution facilities removed, the consumer pays a Facility Standby Charge to avoid paying a reconnection charge for new service in the future.

Minimum Charges

Amount paid to recover a minimum level of fixed costs, including demand and consumer costs, associated with providing service to a consumer on the applicable rate schedule.

Power Factor Charges

Electric motors and other electrical equipment place a demand for reactive (or the component of power that is not useful) power as well as real (or useful) power on the electric system. The power factor adjustment is intended to encourage more efficient use of energy by either adjusting the consumer's demand for billing purposes when the reactive power is more than a stated percentage of the real power or by billing reactive power separately for such excess reactive power. The power factor adjustment generally applies to wholesale rates and the commercial and industrial rate classes.

Power Production and Fuel Adjustment Clauses

The energy charges in a utility's base rates are normally set to recover an anticipated amount of production cost per kWh. If the actual production cost per kWh varies from the anticipated base amount, the power production and fuel adjustment clauses allow the utility to pass this change through to the consumer either as an increase or a decrease.

Transmission and Delivery Charges

Amount paid for the recovery of transmission and distribution costs incurred by a utility in delivering power and energy to a consumer. Also referred to as wheeling service, the utility transmits power and energy from a generation source through its transmission and distribution facilities to the consumer.

Voltage Level Discounts

Base electric rates generally are designed for consumers utilizing all levels of the production, transmission and distribution system. Since some consumers receive their energy at a higher voltage, primary service (which can include transmission and subtransmission voltages), discounts are provided to reflect the portion of the distribution system not utilized and the reduced energy losses required to serve these consumers.

TERMS AND CONDITIONS

Code Inspections

The utility maintains the right to inspect wiring on the consumer's premises to ensure that it meets National Electrical Safety Code standards. The consumer is responsible for securing any required local permits for wiring on their premises.

Consumer Classes

Groups of consumers with similar load characteristics that receive similar types of service. Such consumers are grouped together for purposes of designing rates.

Consumer Responsibilities

Responsibilities generally include safe access to and the maintenance of safe and adequate protection of the utility's equipment installed on the consumer's property. This includes the support for attachment of the utility's overhead or underground service wires and adequate space for the utility's metering equipment. Consumers also have the responsibility to inform the utility of any major load additions to their facilities and also the estimated size of their load requirements at the time of application for electric service to insure billing on the proper rate schedule.

Deposits

In order to start a new service, reconnect a service, or provide service under special conditions, the consumer may be required to provide a deposit. Consumers without a credit rating or who are deemed to be a credit risk are usually required to provide a deposit before service is provided.

Disconnection of Service

Conditions under which a consumer's service may be terminated, including failure to pay an electric bill, energy theft, or the improper use of the utility's equipment which could damage equipment, disrupt service to other consumers, or result in a safety hazard for other consumers, utility personnel, or themselves.

Easements

Rights to property that a utility may obtain for purposes of building transmission or distribution systems. The consumer normally is required to provide the needed easements across the consumer's property for the utility's lines or extensions to the point of delivery.

Extension and New Load Conditions

Policy and/or procedures established by a utility to determine when service will be upgraded to consumers to extend additional delivery points or add new load to existing delivery points. Since this will likely involve additional capital investment, the consumer may be required to pay for a portion of the cost if appropriate.

Firm Power

Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Liability Conditions

Provision to release the utility from liability for loss and damage due to interruption of service, injury or death of persons, or damage to property on the consumer's premises or under the consumer's control, unless such loss, damage or injury is due to the utility's negligence

Load Characteristics

The nature of the consumer's load may be expressed as a load factor representing the ratio of the average load in kilowatts supplied during a designated period (generally monthly) to the maximum demand in kilowatts occurring in that period. Load factor is a measurement of the electrical efficiency of a consumer's operation.

Non-Firm Power

Power or power producing capacity supplied or available under an arrangement which does not have the guaranteed continuous availability feature of firm power.

Phase of Supply

Single-Phase Supply refers to a two-wire or a three-wire system (consisting of 1 or 2 phase wires and 1 neutral wire and specified by a nominal voltage as measured between the phase and the neutral wire (120 volts) or phase to phase (240 volts).

Three-Phase Supply refers to a four-wire system (consisting of 3 phase wires and 1 neutral wire) and specified by the two nominal voltages. One voltage as measured between two phase wires and the second voltage as measured between and phase wire and neutral. Examples might be 120/208 volts or 277/480 volts.

Whether a customer needs single phase or three phase supply is dependent on the size of the load and the distance from a major voltage source.

Point of Delivery

Point where the utility supplies service to a consumer. Generally, this is the point where the utility's service wires are joined to the consumer's service terminals which is typically the location of the electric meter.

Relocation Practices

Provisions relevant to the reestablishment of service when a consumer wishes to change the point of delivery or the routing of the utility equipment to the point of delivery.

Resale and Redistribution Policy at Retail

Provisions to identify under what circumstances, if any, a retail consumer may resell or redistribute electricity purchased from the utility. For example, the owner of a commercial building might be allowed to redistribute electricity to the tenants of the building.

Size and Type of Load

Commonly referred to as demand and expressed in kilowatts, a measure of the rate at which electric energy is delivered over a designated time period to a consumer. For any given consumer or consumer class, the type of load reflects the time period over which the consumer(s) place demand on the utility's system relative to other consumers and the system in total. This includes base load which is the minimum load over a given period of time and peak load which is when the consumer(s) place their greatest demand on the utility's system.

System Responsibilities

The utility intends to provide, but does not guarantee, uninterrupted service to the consumer in accordance with the specific rate schedule that the consumer is taking service. Utility responsibilities also include providing power within specified voltage ranges, absent uncontrollable, events so as not to harm consumer equipment.

Term of Service Agreement

Also referred to as contract period, the length of time a consumer is obligated to take electric service and the utility is obligated to provide electric service under the specific agreement, contract, or rate schedule.

Voltage Delivery and Availability

Relative to each rate schedule offered by a utility, this is a statement of the conditions under which service will be offered to consumers. Consumers requesting service at a voltage level different from the standard offering of the utility are usually required to provide funding in aid-to-construction for such facilities.

Where Available/Service Area

Statement of the area or locale in which service may be offered by a utility, based on jurisdictional boundaries established by the Nebraska Power Review Board.

Others

Any other provisions pertinent to the service to be provided to the consumer. This might include unmetered service, temporary service, parallel operation of consumer's generating equipment, connection and disconnection of service fees, late payments, or bad check fees.

GENERAL DISCUSSION

Seasonal Rates

Comparing components from rate schedules and terms and conditions of other utilities across the nation to Nebraska's supports the premise that Nebraska has no significant differences in rate structure or type of services offered. Most Nebraska utilities utilize seasonal rate structures. Typically the charges are higher in the summer months than in the winter. The number of summer months varies from four to six from utility to utility. Seasonal rates reflect the higher cost of serving higher summer loads and the lower cost of excess capacity available in the winter months.

Time-of-Day Interruptible Rates

Some of Nebraska's larger utilities offer optional time-of-day (TOD) rates to their large commercial, industrial and irrigation customers. Only a few commercial and industrial customers have elected these optional rates across the state. However, over ten thousand irrigation accounts are billed under an interruptible and TOD based rate. Nationwide several utilities offer optional TOD rates to smaller loads such as residential or small commercial. However, none are currently offered in Nebraska. NPPD, OPPD and LES have studied TOD rates for smaller loads as potential demand side management programs. They have found the extra cost of metering and administration outweighs the benefits to the system in terms of load shifting and the benefits to the customer in terms of lower bills. TOD rates are a necessary element for customer owned storage heating and cooling systems to be viable.

Irrigation Rates

A particular type of service and associated rate schedules offered in Nebraska that is not generally offered across the nation is irrigation service. Because of the unique ground water conditions in Nebraska, the State has the highest proportion of center pivot and gravity flow irrigation of any state in the nation. An irrigation load is a very good candidate for demand side management. Several Nebraska utilities provide an incentive for irrigation customers to operate their facilities off peak, generally during the evening and weekends, in order to shift load away from late-afternoon-week days during the summer. The amount of irrigation load shifting would approach approximately 240 MW. Other demand side management programs include air conditioner and water heater load control and interruptible rates. These are strategic conservation rate options primarily in the form of incentives for customers to buy efficient heat pumps, water heaters, and air conditioners.

Economic Development Rates

The Nebraska Legislature in 1995 passed the Nebraska Quality Jobs Act (LB 829) whose purpose was to stimulate economic development within Nebraska. This Act provides economic incentives for new business or for existing business expansion which meet either (1) 250 new jobs and $100 million of investment or (2) 500 new jobs and $50 million of investment. Coupled with this legislation, LB 828 was also adopted which allows municipalities and power districts in the State the ability to negotiate, fix, and establish rates different from those of other users and consumers. These different rates can be effective for a period not to exceed five years.

To qualify for these special economic development rates, the consumer must receive approval from a Board consisting of the Governor, State Treasurer, and Chairperson of the Nebraska Investment Council. Further qualifications require the new or additional energy consumption from the facility to have a minimum electrical demand of five thousand kilowatts with a minimum annual load factor of 55%. However, in no case shall the rate charged the consumer be less than the marginal cost of supplying electricity.

The Quality Jobs Act has a sunset provision included in the legislation. The Act expires on February 1, 2000, unless reauthorized by the Legislature. Since LB 828 is coupled with the Act, the authority to offer incentive rates would expire January 1, 2000 unless reauthorized.

Currently, there are no consumers taking advantage of LB 828. However, Cargill, Union Pacific, Sandoz Pharmaceuticals, and FDR have applied and have been approved to receive benefits under LB 829. However, none of the incentives would be available to any of the above businesses until the criteria established for job creation, investment, and energy consumption are satisfied.

LISTING OF NEBRASKA ELECTRIC UTLITY SYSTEMS AND NUMBER OF CUSTOMERS*

(Source: DOE EIA Form 861, 1995)

Utility Name	Residential	Commercial	Industrial	Other	Total
Alliance, City of	4,028	665	4	288	4,975
Ansley, City of	275	59	0	1	335
Arapaho, City of	495	106	0	50	653
Arnold, Village of	365	130	0	35	530
Auburn, City of	2,255	486	20	25	2,786
Bartley, Village of	222	0	0	0	222
Battle Creek, City of	440	73	3	24	540
Bayard, City of	585	144	6	0	735
Beatrice, City of	5,625	775	130	357	6,887
Beaver City, City of	370	60	0	0	430
Benkelman, City of	497	146	0	1	644
Blue Hill, City of	340	74	2	26	442
Bradshaw, Village of	150	24	9	15	198
Brainard, Village of	200	0	0	0	200
Bridgeport, City of	704	186	0	3	893
Broken Bow, City of	1,858	401	3	4	2,266
Burt County PPD	3,165	144	21	340	3,670
Burwell, City of	599	152	1	6	758
Butler County PPD	3,398	138	734	12	4,282
Callaway, Village of	290	75	0	0	365
Cambridge, City of	501	142	0	1	644
Campbell, Village of	192	57	1	1	251
Cedar-Knox PPD	3,927	188	0	473	4,588
Central City, City of	1,448	342	10	0	1,800
Central Nebraska PP&ID	0	0	0	0	0
Chappell, City of	561	108	1	4	674
Chester, Village of	174	75	0	0	249
Chimney Rock PPD	1,713	242	0	376	2,331
Clarkson, City of	356	94	0	0	450
Cornhusker PPD	5,140	220	7	2,469	7,836
Cozad, City of	1,664	310	8	37	2,019
Crete, City of	2,059	375	3	3	2,440
Cuming County PPD	2,669	6	1	6	2,682
Curtis, City of	552	145	10	0	707
Custer PPD	4,237	754	0	3,604	8,585
David City, City of	1,027	192	29	11	1,259
Dawson County PPD	11,442	750	3	4,143	16,338
Davenport, Village of	182	55	0	0	237
DeWitt, Village of	266	28	1	11	306

Utility Name	Residential	Commercial	Industrial	Other	Total
Decatur, Village of	388	67	0	0	455
Deshler, City of	462	109	0	1	572
Dorchester, Village of	236	25	0	12	273
Edgar, City of	260	80	9	3	352
Elk Creek, Village of	68	7	0	0	75
Elkhorn, Rural PPD	5,593	209	22	1,011	6,835
Emerson, City of	334	83	0	0	417
Endicott Village of	75	3	0	0	78
Fairbury, City of	3,465	620	0	1	4,086
Fairmont, City of	261	63	0	2	326
Filley, City of	80	24	0	0	104
Falls City, City of	2,276	539	32	1	2,848
Franklin, City of	550	145	0	1	696
Fremont, City of	10,778	1,376	435	3	12,592
Friend, City of	502	152	0	0	654
Gering, City of	3,021	373	46	45	3,485
Giltner, City of	160	34	0	0	194
Gothenburg, City of	1,343	296	12	24	1,675
Grand Island, City of	17,487	3,111	64	129	20,791
Grant, City of	598	162	0	1	770
Greenwood, City of	232	20	0	0	252
Hampton, Village of	199	37	0	14	250
Hastings, City of	9,984	1,768	80	106	11,938
Hebron, City of	809	232	0	1	1,042
Hemingford, Village of	388	109	4	27	528
Holbrook, Village of	102	7	0	0	109
Holdrege, City of	2,565	434	2	24	3,025
Howard Greeley Rural PPD	2,423	189	510	33	3,155
Hubbell, City of	41	14	1	0	56
Imperial, City of	834	289	18	8	1,149
Indianola, City of	320	29	0	3	352
KBR Rural PPD	1,856	1,120	0	282	3,258
Kimball, City of	1,255	375	4	18	1,652
Hickman, City of	376	67	1	0	444
Hildreth, Village of	236	0	0	0	236
Laurel, City of	425	80	0	3	508
Leigh, Village of	292	0	0	0	292
Lexington, City of	3,208	560	2	5	3,775
Lincoln Electric System	87,393	11,372	237	1,313	100,315
Lodgepole, City of	199	64	0	0	263
Loup Valley Rural PPD	2,856	217	0	728	3,801
Loup River PPD	13,486	2,744	38	741	17,009
Lyman, Village of	179	55	10	9	253

Utility Name	Residential	Commercial	Industrial	Other	Total
Lyons, City of	512	118	0	6	636
Madison, City of	796	164	2	0	962
McCook PPD	3,120	415	791	47	4,373
Midwest Electric MC	2,816	824	1,219	12	4,871
Minden, City of	1,247	249	0	6	1,502
Mitchell, City of	827	162	1	3	993
Morrill, Village of	682	150	6	30	868
Mullen, Village of	322	73	0	0	395
Neligh, Village of	770	226	1	63	1,060
Nebraska City, City of	4,369	794	22	10	5,195
Nebraska PPD	85,368	19,366	68	4,194	108,996
Nelson, City of	305	52	0	27	384
Niobrara Valley Electric MC	4,018	649	0	99	4,766
Norris PPD	10,141	2,810	64	61	13,076
North Central PPD	2,600	1,085	0	15	3,700
North Platte, City of	11,978	2,039	0	2	14,019
NE Nebraska Rural PPI	2,528	252	17	14	2,811
NW Nebraska Rural PPD	1,501	156	476	628	2,761
Omaha PPD	233,879	33,137	97	542	267,655
Ord, City of	1,137	244	0	4	1,385
Panama, Village of	104	0	0	0	104
Oxford, Village of	429	83	3	1	516
Panhandle Rural EM Assoc.	1,862	1,532	2	13	3,409
Pender, City of	529	157	0	0	686
Pierce, City of	860	149	0	23	1,032
Plainview, City of	656	130	0	20	806
Polk County Rural PPD	1,724	120	2	768	2,614
Polk, Village of	207	50	0	0	257
Prague, Village of	164	22	0	2	189
Randolph, City of	462	130	3	0	595
Red Cloud, City of	648	142	9	0	799
Reynolds, Village of	59	9	0	0	68
Roosevelt PPD	2,091	52	281	5	2,429
Scribner, City of	450	112	0	19	581
Sargent, City of	342	89	0	15	446
Schuyler, City of	1,950	258	22	21	2,251
Shickley, Village of	202	21	0	6	229
Seward, City of	2,391	283	3	1	2,678
Seward County Rural PPD	1,699	940	1	9	2,649
Sidney, City of	2,591	529	26	4	3,150
Snyder, City of	140	34	5	8	187
South Central PPD	2,958	1,381	5	5	4,349
South Sioux City, City of	4,728	745	0	0	5,473

Utility Name	Residential	Commercial	Industrial	Other	Total
S Nebraska Rural PPD	10,771	943	137	7,055	18,906
Southwest PPD	3,614	648	10	993	5,265
Spalding, Village of	280	115	0	0	395
Spencer, City of	275	58	0	1	334
St Paul, City of	905	214	9	0	1,128
Stanton County PPD	1,840	710	1	56	2,607
Stratton, City of	209	54	0	19	282
Stromsburg, City of	501	118	9	24	652
Stuart, City of	270	100	0	3	373
Superior, City of	1,157	258	10	35	1,460
Sutton, City of	664	138	0	7	809
Syracuse, City of	754	142	8	12	916
Talmage, Village of	118	35	0	1	154
Tecumseh, City of	824	202	3	14	1,043
Trenton, City of	343	89	0	12	444
Twin Valleys PPD	3,301	594	0	662	4,557
Valentine, City of	1,332	342	0	0	1,674
Wahoo, City of	1,604	301	28	34	1,967
Wakefield, City of	540	60	1	1	602
Walthill, Village of	294	45	0	0	339
Wauneta, Village of	332	91	15	29	467
Wayne, City of	1,849	306	0	70	2,225
Wayne County PPD	2,386	213	76	14	2,689
West Point, City of	1,462	301	64	5	1,832
Wheatbelt PPD	3,156	493	3	813	4,465
Wilber, City of	875	115	4	17	1,011
Wilcox, Village of	167	37	0	0	204
Winside, Village of	251	13	0	1	265
Wisner, City of	609	149	1	0	759
Wood River, City of	412	115	0	0	527
Wymore, City of	750	135	0	1	886
York County Rural PPD	2,254	201	3	2,199	4,657
Municipal Energy Agency of Nebraska	0	0	0	0	0
Nebraska Electric G&T Co-operative, Inc.	0	0	0	0	0
Totals for State	681,827	112,441	6,042	35,174	835,946

*Note: The customer data above drawn from DOE EIA Form 861 varies slightly from the adjusted customer data noted in the L.R. 455 Survey (i.e. total customers from the L.R. 455 Survey shows 835,905 rather than 835,946). This customer data also does not include 5,464 Nebraska customers served by rural cooperatives based in neighboring states (see Rural Distribution Cooperatives Listing).

RURAL DISTRIBUTION COOPERATIVES*				
Cooperative/Location	1995 Annual Revenues	Customers (meters)	Miles of Line	Employees
Cherry-Todd ECI, Mission, SD (3)	$841,350.00	637	536	2
Highline Electric Assn., Holyoke, CO (2)	4,595,105.00	1,876	n/a	0
LaCreek Electric Assn., Martin, SD (3)	246,567.00	196	283	0
Midwest ECC, Grant, NE (2)	10,417,198.00	5,052	2,531	29
NCK Electric Co-op, Belleville, KS (4)	10,561.00	8	1	0
Niobrara Electric Assn., Lusk, WY (2)	565,970.00	798	560	2
Niobrara Valley EMC, O'Neill, NE (1)	5,600,249.00	4,757	2,513	24
Panhandle REMA, Alliance, NE (2)	7,009,410.00	3,373	2,738	22
Rural Electric Co., Pine Bluffs, WY (2)	5,366,647.00	1,432	2,590	6
Wyrulec Co., Lingle, WY (2)	783,296.00	433	427	0
Y-W Electric Assn., Akron, CO (2)	495,614.00	84	38	0
Totals	$35,931,967.00	18,646	12,217	85

*All figures for co-ops headquartered in other states are system statistics on Nebraska operations only.

(1) Nebraska Electric Generation & Transmission Cooperative/NPPD
(2) Tri-State Generation & Transmission Association
(3) Rushmore Electric Power Cooperative/Basin Electric
(4) Kansas Electric Power Generation & Transmission Cooperative (not discussed in the text because of small number of electric consumers in the state)

RURAL DISTRIBUTION POWER DISTRICTS				
District/Location	1995 Annual Revenues	Customers (meters)	Miles of Line	Employees
Burt County PPD, Tekamah (1)	$4,784,507.00	3,745	2,046	21
Butler County RPPD, David City (1)	4,096,193.00	4,242	1,450	16
Cedar-Knox PPD, Hartington (3)	5,298,964.00	4,548	1,804	22
Chimney Rock PPD, Bayard (2)	2,883,414.00	2,259	862	10
Cornhusker PPD, Columbus (1)	10,071,577.00	7,793	3,286	47
Cuming County PPD, West Point (1)	4,081,199.00	2,667	1,439	19
Custer PPD, Broken Bow (1)	7,852,126.00	8,553	4,594	50
Dawson PPD, Lexington (1)	15,870,177.00	16,238	5,123	69
Elkhorn RPPD, Battle Creek (1)	7,414,505.00	6,804	2,517	33
Howard Greeley RPPD, St. Paul (1)	3,377,907.00	2,946	2,126	16
KBR RPPD, Ainsworth (1)	3,087,636.00	3,249	2,358	15
Loup Valleys RPPD, Ord (1)	3,067,074.00	3,800	1,923	16
McCook PPD, McCook (1)	6,933,153.00	4,735	2,590	31
Norris PPD, Beatrice (3)	22,187,928.00	13,015	4,518	70
North Central PPD, Creighton (1)	3,764,798.00	3,800	1,477	17
Northeast NE RPPD, Emerson (1)	3,746,449.00	2,777	1,330	19
Northwest RPPD, Hay Springs (2)	4,622,691.00	2,745	2,133	18
Polk County RPPD, Stromsburg (1)	2,885,320.00	2,587	858	14
Roosevelt RPPD, Mitchell (2)	2,945,429.00	2,571	680	10
Seward County RPPD, Seward (1)	3,326,879.00	2,702	931	14
South Central PPD, Nelson (1)	4,919,292.00	4,347	2,128	19
Southern NE RPPD, Grand Island (1)	23,043,345.00	18,789	6,387	77
Southwest RPPD, Palisade (1)	8,063,651.00	5,481	2,286	35
Stanton County PPD, Stanton (1)	2,904,408.00	2,579	749	14
Twin Valleys PPD, Cambridge (1)	4,056,841.00	4,587	2,336	20
Wayne PPD, Wayne (1)	3,101,524.00	2,688	1,177	14
Wheat Belt PPD, Sidney (2)	8,646,769.00	4,435	2,446	29

York County RPPD, York (1)	6,620,136.00	4,606	1,908	26
Totals	$183,653,892.00	149,288	63,462	761

(1) Nebraska Electric Generation & Transmission Cooperative/NPPD
(2) Tri-State Generation & Transmission Association
(3) Contracts directly with Nebraska Public Power District

CHAPTER THREE APPENDIX SECTION

ADDITIONAL STATE AGENCIES THAT REGULATE OR ASSIST ELECTRIC UTILITIES

Department of Health and Human Services (DOHHS)

The DOHHS has state regulatory authority over asbestos management and lead abatement. It also is responsible for emergency response and environmental surveillance at the state's two nuclear power plants and shares responsibility for the regulation of low-level radioactive waste with the DEQ.

Department of Labor (DOL)

The DOL is responsible for administration of the federal wage and hour legislation and administers the state's Workplace Safety Consultation Program which requires all employers in the state to have safety communities and adopt injury prevention programs.

Department of Water Resources (DWR)

The DWR enforces Nebraska's water laws and is responsible for issuing and administering any water rights needed for the state's electric generation facilities. The DWR interacts with FERC regarding water rights for hydroelectric facilities. Any transfer of these water rights or leases must be approved by DWR.

KEY FEDERAL AGENCIES THAT REGULATE OR ASSIST ELECTRIC UTILITIES

Department of Energy (DOE)

Some Nebraska utilities, because of size, must comply with reporting requirements by supplying information on fuels, rates, revenues, energy consumption and customers. Cogeneration is also regulated by DOE.

Federal Energy Regulatory Commission (FERC)

Construction of hydroelectric facilities on navigable streams in Nebraska required FERC licensing. Many of these licenses were issued on the 1930's for 50 years, and recently have been or currently are being renewed. These licenses cover power plants at Lake McConaughy, North Platte, Johnson 1 and 2, Jeffrey Lake, Columbus, and Monroe, as well as cooling for Gerald Gentleman and Canaday Station. Transfers of these licenses require FERC approval.

Environmental Protection Agency (EPA)

A wide variety of environmental regulations affect utilities. These include regulations issued under the Clean Air Act, Clean Water Act, the Toxic Substance Control Act, the Resource Conservation Recovery Act, and Superfund.

Nuclear Regulatory Commission (NRC)

All nuclear power plants require an NRC license and are subject to ongoing NRC regulation. Changes in the structure of a utility owning/operating a nuclear power plant requires NRC approval.

Internal Revenue Service (IRS)

As discussed in chapters 5 and 6, the IRS has far-reaching control over the use of utility facilities based upon restrictions on tax-exempt financing.

CHAPTER FOUR APPENDIX SECTION

4-1

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
Fremont	Fremont #6	F	C	1958	15.00	
Fremont	Fremont #7	F	C	1963	20.00	
Fremont	Fremont #8	F	C	1977	85.00	
Fremont	Total					120.00
LES	8Th & Jst	CT	NG/O	1972	27.90	
LES	Rokeby	CT	NG/O	1975	74.40	
LES	Laramie #1(With Seas exc)	F	C	1982	217.92	
LES	Total					320.22
Auburn	Auburn #1	D	NG/O	1981	2.41	
Auburn	Auburn #2	D	NG/O	1949	1.00	
Auburn	Auburn #4	D	NG/O	1993	3.75	
Auburn	Auburn #5	D	NG/O	1973	3.35	
Auburn	Auburn #6	D	NG/O	1967	2.75	
Auburn	Auburn #7	D	NG/O	1987	5.60	
Auburn	Total					18.86
Falls City	Falls City #1	D	O	1930	0.68	
Falls City	Falls City #2	D	O	1937	0.56	
Falls City	Falls City #3	D	NG/O	1965	2.75	
Falls City	Falls City #4	D	NG/O	1946	1.13	
Falls City	Falls City #5	D	NG/O	1951	2.00	
Falls City	Falls City #6	D	NG/O	1958	2.50	
Falls City	Falls City #7	D	NG/O	1973	6.25	
Falls City	Falls City #8	D	NG/O	1981	6.00	
Falls City	Total					21.87
Grand Island	Burdick #1	F	NG/O	1957	16.50	
Grand Island	Burdick #2	F	NG/O	1963	22.30	
Grand Island	Burdick #3	F	NG/O	1971	54.00	
Grand Island	Burdick Gas Turbine	CT	NG/O	1968	14.80	
Grand Island	Platte Generating Station	F	C	1982	100.00	
Grand Island	Total					207.60
Hastings	Whelan Energy Center #1	F	C	1982	72.00	
Hastings	Hastings-NDS #4	F	NG/O	1957	13.00	
Hastings	Hastings-NDS #5	F	NG/O	1967	20.00	
Hastings	Hastings #1	CT	O	1972	18.00	
Hastings	Total					123.00
Nebraska City	Nebraska City #2	D	NG/O	1953	1.53	
Nebraska City	Nebraska City #3	D	NG/O	1955	2.50	
Nebraska City	Nebraska City #4	D	NG/O	1957	3.10	
Nebraska City	Nebraska City #5	D	NG/O	1964	2.00	
Nebraska City	Nebraska City #6	D	NG/O	1967	2.00	
Nebraska City	Nebraska City #7	D	NG/O	1969	2.00	
Nebraska City	Nebraska City #8	D	NG/O	1970	4.10	
Nebraska City	Nebraska City #9	D	NG/O	1974	6.42	
Nebraska City	Nebraska City #10	D	NG/O	1979	6.50	
Nebraska City	Total					30.15
Wahoo	Wahoo #1	D	NG/O	1960	2.00	
Wahoo	Wahoo #2	D	O	1936	0.40	
Wahoo	Wahoo #3	D	NG/O	1973	4.30	
Wahoo	Wahoo #4	D	NG/O	1947	1.00	
Wahoo	Wahoo #5	D	NG/O	1952	2.10	
Wahoo	Wahoo #6	D	NG/O	1969	3.40	
Wahoo	Total					13.20

Unit Type		Fuel Type	
H-	Hydro	HS-	Run of River
D-	Diesel	NG-	Natural Gas
N-	Nuclear	O-	Oil
CT-	Combustion Turbine	C-	Coal
F-	Fossil	HR-	Reservoir
		UR-	Uranium

APPENDIX - IRP COORDINATION REPORT

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4-2

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
NPPD	Sutherland #1	D	O	1952	0.40	
NPPD	Sutherland #2	D	O	1959	0.95	
NPPD	Sutherland #3	D	O	1935	0.15	
NPPD	Sutherland #4	D	O	1964	1.20	
NPPD	Wakefield #2	D	NG/O	1955	0.54	
NPPD	Wakefield #4	D	NG/O	1961	0.69	
NPPD	Wakefield #5	D	NG/O	1966	1.07	
NPPD	Wakefield #6	D	NG/O	1971	1.13	
NPPD	Wayne #1	D	O	1952	0.75	
NPPD	Wayne #3	D	O	1956	1.75	
NPPD	Wayne #4	D	O	1960	1.85	
NPPD	Wayne #5	D	O	1966	3.25	
NPPD	Wayne #6	D	O	1968	4.90	
NPPD	Total					2710.88

APPENDIX - IRP COORDINATION REPORT

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
NPPD	Canaday #1	F	NG/O	1958	0.00	Layed up
NPPD	Columbus-Monroe #1	H	HR	1936	13.30	
NPPD	Columbus-Monroe #2	H	HR	1936	13.30	
NPPD	Columbus-Monroe #3	H	HR	1936	13.40	
NPPD	Cooper #1	N	UR	1974	774.00	All of Cooper
NPPD	David City #1	D	NG/O	1960	1.30	
NPPD	David City #2	D	NG/O	1949	0.80	
NPPD	David City #3	D	NG/O	1955	0.90	
NPPD	David City #4	D	NG/O	1966	1.80	
NPPD	Gentleman #1	F	C	1979	665.00	
NPPD	Gentleman #2	F	C	1982	700.00	
NPPD	Hallam #1	CT	NG/O	1973	50.00	
NPPD	Hebron #1	CT	NG/O	1973	50.00	
NPPD	Holdredge #1	D	O	1938	0.50	
NPPD	Holdredge #2	D	O	1952	1.00	
NPPD	Holdredge #3	D	O	1945	0.50	
NPPD	Jeffrey #1	H	HR	1940	9.00	
NPPD	Jeffrey #2	H	HR	1940	9.00	
NPPD	Johnson I #1	H	HR	1940	9.00	
NPPD	Johnson I #2	H	HR	1940	9.00	
NPPD	Johnson II #1	H	HR	1940	18.00	
NPPD	Kearney #1	H	HR	1921	1.00	
NPPD	Kingsley #1	H	HR	1985	38.00	
NPPD	Lodgepole #1	D	O	1934	0.15	
NPPD	Lodgepole #2	D	O	1947	0.10	
NPPD	Lyons #2	D	O	1960	0.40	
NPPD	Lyons #3	D	O	1953	0.70	
NPPD	Madison #1	D	NG/O	1969	1.70	
NPPD	Madison #2	D	NG/O	1959	0.95	
NPPD	Madison #3	D	NG/O	1953	0.85	
NPPD	Madison #4	D	O	1946	0.50	
NPPD	McCook #1	CT	O	1973	49.00	
NPPD	North Platte #1	H	HR	1935	12.00	
NPPD	North Platte #2	H	HR	1935	12.00	
NPPD	Ord #1	D	NG/O	1973	5.00	
NPPD	Ord #2	D	NG/O	1966	1.30	
NPPD	Ord #3	D	NG/O	1963	2.00	
NPPD	Sheldon #1	F	C	1961	105.00	
NPPD	Sheldon #2	F	C	1965	120.00	
NPPD	Spencer #1	H	HS	1927	0.80	
NPPD	Spencer #2	H	HS	1952	1.00	

APPENDIX - IRP COORDINATION REPORT

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
OPPD	Fort Calhoun #1	N	UR	1973	476.00	
OPPD	Nebraska City #1	F	C	1979	584.90	
OPPD	North Omaha #1	F	C	1954	75.60	
OPPD	North Omaha #2	F	C	1957	110.50	
OPPD	North Omaha #3	F	C	1959	110.50	
OPPD	North Omaha #4	F	C	1963	133.20	
OPPD	North Omaha #5	F	C	1968	214.70	
OPPD	Jones St #1	CT	O	1973	54.70	
OPPD	Jones St #2	CT	O	1973	54.70	
OPPD	Sarpy County #1	CT	NG/O	1972	51.40	
OPPD	Sarpy County #2	CT	NG/O	1972	51.40	
OPPD	Sarpy County #3	CT	NG/O	1996	105.40	
OPPD	Tecumseh #1	D	O	1949	0.60	
OPPD	Tecumseh #2	D	O	1968	1.40	
OPPD	Tecumseh #3	D	O	1952	1.00	
OPPD	Tecumseh #4	D	O	1960	1.20	
OPPD	Tecumseh #5	D	O	1993	2.40	
OPPD	Total					2029.60

APPENDIX - IRP COORDINATION REPORT

4-5

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
MEAN	Arnold #1	D	NG/O	1960	0.60	
MEAN	Arnold #3	D	NG/O	1942	0.20	
MEAN	Arnold #4	D	NG/O	1946	0.30	
MEAN	Beaver City#1	D	NG/O	1958	0.43	
MEAN	Beaver City#2	D	NG/O	1961	0.28	
MEAN	Beaver City#4	D	NG/O	1968	0.71	
MEAN	Benkelman #5	D	O	1953	0.80	
MEAN	Blue Hill #1	D	NG/O	1964	0.79	
MEAN	Blue Hill #2	D	O	1948	0.46	
MEAN	Broken Bow #1	D	O	1933	0.50	
MEAN	Broken Bow #2	D	NG/O	1971	3.43	
MEAN	Broken Bow #3	D	NG/O	1936	0.82	
MEAN	Broken Bow #4	D	NG/O	1949	0.81	
MEAN	Broken Bow #5	D	NG/O	1959	1.00	
MEAN	Broken Bow #6	D	NG/O	1961	2.04	
MEAN	Burwell #1	D	NG/O	1955	0.53	
MEAN	Burwell #2	D	NG/O	1962	0.71	
MEAN	Burwell #3	D	NG/O	1967	0.89	
MEAN	Burwell #4	D	NG/O	1972	1.07	
MEAN	Callaway #1	D	O	1936	0.20	
MEAN	Callaway #2	D	O	1948	0.20	
MEAN	Callaway #3	D	O	1959	0.50	
MEAN	Chappell #2	D	O	1945	0.20	
MEAN	Chappell #3	D	O	1982	1.00	
MEAN	Crete #1	D	NG/O	1939	0.48	
MEAN	Crete #2	D	NG/O	1955	1.31	
MEAN	Crete #3	D	NG/O	1951	1.00	
MEAN	Crete #4	D	NG/O	1947	1.01	
MEAN	Crete #5	D	NG/O	1962	3.00	
MEAN	Crete #6	D	NG/O	1965	3.60	
MEAN	Crete #7	D	NG/O	1972	6.25	
MEAN	Curtis #1	D	NG/O	1975	1.30	
MEAN	Curtis #2	D	NG/O	1969	1.12	
MEAN	Curtis #4	D	NG/O	1955	0.90	
MEAN	Fairbury #2	F	NG/O	1948	4.30	
MEAN	Fairbury #4	F	NG/O	1966	11.90	
MEAN	Kimball # 1	D	NG/O	1955	1.10	
MEAN	Kimball # 2	D	NG/O	1956	0.95	
MEAN	Kimball # 3	D	NG/O	1959	1.20	
MEAN	Kimball # 4	D	NG/O	1960	1.20	
MEAN	Kimball # 5	D	NG/O	1951	0.65	
MEAN	Kimball # 7	D	NG/O	1975	3.90	
MEAN	Laramie #1	F	C	1982	10.00	
MEAN	Oxford #1	D	O	1948	0.44	
MEAN	Oxford #2	D	NG/O	1952	0.43	
MEAN	Oxford #3	D	NG/O	1956	0.66	
MEAN	Oxford #4	D	NG/O	1956	0.37	
MEAN	Oxford #5	D	O	1972	0.90	

APPENDIX - IRP COORDINATION REPORT

4-6

utility	unit name	unit type	Fuel type	commercial date	Capacity	Utility Capacity
MEAN	Pender #1	D	O	1967	1.06	
MEAN	Pender #2	D	NG/O	1973	1.71	
MEAN	Pender #3	D	O	1953	0.44	
MEAN	Pender #4	D	O	1961	0.75	
MEAN	Pender #5	D	O	1939	0.04	
MEAN	Red Cloud #2	D	NG/O	1953	0.50	
MEAN	Red Cloud #3	D	NG/O	1960	1.08	
MEAN	Red Cloud #4	D	NG/O	1968	1.04	
MEAN	Red Cloud #5	D	NG/O	1974	1.58	
MEAN	West Point #1	D	NG/O	1950	2.15	
MEAN	West Point #2	D	NG/O	1959	1.05	
MEAN	West Point #3	D	NG/O	1965	0.69	
MEAN	West Point #5	D	NG/O	1971	3.95	
MEAN	Total					92.48

COMPARISON OF GENERATING UTILITIES

Nebraska's two largest power districts, which cover the majority of the state's population, are Nebraska Public Power District and Omaha Public Power District.

The nation's top 100 generating utilities are listed in an annual report called "Powerdat" each year. Nebraska Public Power District and Omaha Public Power District appeared several times in this annual report providing information about utility operations during the calendar year 1995. This data base, which covers more than 5,000 companies, including electric investor-owned utilities, municipal utilities, rural electric cooperatives, public authorities, non-utility generators and power marketers, has been used to define the nation's top 100 operating utilities.

According to *Electric Light and Power*, October 1996, Volume 74, Number 10, Industry report on the top 100 Electric Utilities, Nebraska's two major power districts made the following lists:

§Top 20 purchasers of wholesale power in 1995:
#16 Nebraska NPPD -Electric System MWh of 11,675,200 at cents/kWh 2.57

§Top 100 generating utilities in 1995 (ranked by total production costs) lowest to highest:
#1 Tennessee Valley Authority
#19 Western Area Power Administration
#65 Nebraska Public Power District
#85 Omaha Public Power District

§Cost Profile of the top 100 generators in 1995 (ranked by total kWh cost) lowest to highest:
#4 Western Area Power Administration
#20 Nebraska Public Power District.
#36 Omaha Public Power District

§Top 20 U.S. steam-electric plants in 1995 (ranked by total production cost) lowest to highest:#8 Nebraska Public Power District, Gentleman
#12 Omaha Public Power District, Nebraska City

RESOURCE ADDITIONS

The 1996 IRP Statewide Coordination Report describes likely future demand- and supply-side resource options. In the DSM section of this LR455 report, the current estimate for demand-side management resources is given. In the Generation Plants Section of the report, the major Nebraska generation resources are listed as of 1995. Integrated resource planning processes have resulted in various additions to future supply-side resources at various levels of commitment since the 1995 time frame:

- Twenty-year extensions of hydro power purchase contracts with Western Area Power Administration, beginning 2001 for Pick-Sloan-Eastern Division (2004 for Loveland Area Projects). Some utilities have executed these contracts and some are in the negotiation process. It is likely that most, if not all, of this available capacity of approximately 845 MW will be purchased. By 2015 this amount may decrease to 805 MW as allowed by contract reductions exercisable by WAPA.

- Generation resource additions since 1995 that have obtained Nebraska Power Review Board approval and their corresponding commercial dates are:

UNIT	TYPE	CAPABILITY	COMMERCIAL DATE
Wilber #2 (MEAN)	Diesel	1.6 MW	1996
Stuart #5 (Municipal) (Part is Replacement)	Diesel	0.8 MW	1996
Sarpy County #3 (OPPD)	Gas Turbine & Black Start Diesel	105.5 MW 3.4 MW	1996 1996
David City #5, 6, 7 (NPPD)	Diesel	4.0 MW	1996
Blue Hill #3 (MEAN)	Diesel	1.8 MW	1997
Rokeby #2 (LES)	Gas Turbine & Black Start Diesel	87 MW 3 MW	1997 1997
Ord #4, 5 (NPPD)	Diesel	2.9 MW	1997 (est.)
Wayne #7, 8 (NPPD)	Diesel	6.4 MW	1997 (est.)
Nebraska City #11, 12, 13 (Nebraska City Utilities)	Nat Gas/Diesel	4.6 MW	1997 (est.)
Iatan II-participation (LES)	Coal	90 MW (initial)	2004 (est.)
Iatan II-participation (LES)	Coal	60 MW (add'l)	2007 (est.)

- NPPD's 345kV transmission additions have made possible full capacity utilization from its Gerald Gentleman Station for a total increase of 87 MW to obtain a plant total capacity of 1365 MW, effective 1996.

- All LES' 115kV transmission additions for Rokeby #2 will be completed by early 1998, including one new interconnection by summer 1997.

- OPPD's Nebraska City Coal Station capability upgrade of 34 MW to a total capability of 619 MW, effective 1997 (est.).

- NPPD's Canaday Steam Plant, 107 MW of gas/oil capability, currently in a lay-up state for future operation. Restart could be 2000, or sooner/later as needed.

- Recent power purchase arranged by OPPD from ENRON Power Marketing and a power sale arranged by NPPD to St. Joseph Light & Power have been included in the Statewide Capability vs. Obligation graph.

- A December 1996 power sale and purchase arrangement by LES to/from ENRON Power marketing was not included in the statewide capability chart but will be incorporated in future statewide submittals to the Nebraska Power Review Board.

- Options under consideration by the Nebraska utilities for their individual IRPs include use of both new and existing plant sites. The non-hydro renewable energy generation option receiving the most attention at this time is wind energy generation, but developments for other types are being monitored as well.

On the demand side, expansions of the current load management, interruptible and other rate options useful for conservation purposes and efficient use of facilities are expected.

The twelve utilities that have recently submitted, or are in the process of developing IRPs, are: Auburn, Falls City, Fremont, Grand Island, Hastings, Lincoln Electric System, Municipal Energy Agency of Nebraska, Nebraska City, Nebraska Public Power District, Omaha Public Power District, Tri-State Generation & Transmission Association, and Wahoo. The latest due date is July 1997. A combined IRP report will be provided to the Nebraska Power Review Board summarizing the twelve IRPs. Public participation and utility board approval prior to IRP submittal are parts of the process.

OUTLOOK ON FUEL PRICES AND AVAILABILITY

Background

As a follow up to the Fuel Diversity section, the following reports the future availability and price outlook for production fuels, i.e., coal, oil and natural gas.

Prices

The U.S. Department of Energy/Energy Information Administration - Office of Integrated Analysis and Forecasting recently published its "Annual Energy Outlook 1997 With Projections to 2015", December, 1996, document number DOE/EIA-0383(97) , also found at Internet web site http://www.eia.doe.gov/oiaf/aeo97, specifically /oilgas.html#prices and /coal.html#production. The fuel price projections of the U.S. DOE are representative of the expectations of several private forecasting groups.

Coal is classified into two broad categories of Eastern and Western coal. Eastern coal generally has a heat content that is fifty percent higher than Western coal. However, at the point where the coal is ready for shipment from the mine, Western coal is less than half the price per ton of Eastern coal, primarily because Western coal is produced from open pit, surface mines and Eastern coal is produced from underground mines. Nebraska is fortunate to be located close to the western coal in the Power River Basin in eastern Wyoming, which has large reserves of low-cost, low-sulfur coal. Wyoming currently produces the most coal of any state. Because of this close proximity to Wyoming coal, Nebraska's delivered prices (to the power plants) are among the lowest in the nation. The U.S. DOE's outlook for nationwide average coal prices projects a 0.9% per year decline (in constant dollars) over the next twenty years. Yet, the average coal prices for Nebraska purchases of high demand, low sulfer Western coal are likely to increase approximately 0.5% per year (constant dollars) over the next twenty years, or increase 0.5% per year above the rate of inflation. However, due to the expiration of long-term coal supply and delivery contracts, the average coal price for Nebraska is at the lower end of the Western market price. Access to second rail carriers at some of Nebraska's power plants provides assurance of long-term competition for the delivery of Western coal.

Oil price is projected by the U.S. DOE to increase by 1.2% per year (constant dollars---the amount of increase above the inflation rate). Similarly, natural gas is projected to increase by 1.4% per year (constant dollars).

The Nuclear Energy Institute (NEI) Nuclear Fuel Marketing issues published its uranium production outlook and provided the following projections. The NEI projections are representative of the expectations of the nuclear industry.

World demand for uranium is expected to rise slowly over the next ten years, as nuclear utilities continue drawing down their inventories and new nuclear plants come on line in the Far East. Western world production -- which excludes the People's Republic of China and the former Soviet Union -- is also expected to rise, but not enough to meet projected demand in the near term.

If uranium supply shortages occur during the next few years, which some analysts think is possible because of the lack of available uranium production in the near term, the price of uranium could rise substantially. In the longer term, however, supply is expected to be sufficient to meet demand.

Although enrichment prices have increased somewhat over the past 18 months, few observers expect that trend to continue. A number of factors -- changes in government influence over the market, a shift in technology from gaseous diffusion plants to other technologies, and buyers' growing insistence on diverse sources of supply -- all promise a more competitive market.

Availability

Nebraska has very minor bituminous coal deposits in the southeast corner of the state. Wyoming has the third largest demonstrated reserve of coal of any state in the nation. The U.S. has approximately 265 billion tons of recoverable coal which is 23% of the world's recoverable coal reserves of approximately 1,145 billion tons. Recoverable coal reserves are demonstrated reserves that can be economically mined using technology currently available or expected to be available in the near future. At the present rate of usage, recoverable reserves of Powder River Basin coal (Wyoming and Montana) would last for 200 years. At the present rates of world and U.S. usage, recoverable reserves of coal would last the world for 200 years, and the U.S. for 250 years. Compared to U.S. reserves of oil and natural gas, coal represents approximately 90% of the nation's fossil fuel energy reserves.

Nebraska has a small amount of oil at approximately 0.1% of the nation's proven reserves. The nation's proven reserves are 2.2% of the world's proven reserves of oil. The world's proven reserves are roughly one trillion barrels, which would last 40+ years at the present rate of world consumption. Interestingly, proven reserves are 80% higher today than 25 years ago because discoveries have exceeded production.

Nebraska has a very small amount of natural gas at approximately 0.04% of the nation's proven reserves. However, natural gas is readily available to Nebraska and is primarily supplied by fields in the midcontinent region.The nation's proven reserves are 3.6% of the world's proven natural gas reserves. The world's proven reserves are roughly 4,700 trillion cubic feet. Technically recoverable gas reserves in the U.S. and Canada are about 2,200 trillion cubic feet vs. 240 being proven. Technically recoverable means that the resource can be found and produced with current industry practices or with reasonably foreseeable advances in technology. Technically recoverable gas reserves would last the U.S. and Canada 90+ years at their present rate of consumption.

U.S. commercial inventories at the beginning of 1995 were estimated to be equivalent to 114 million pounds of uranium - including 28 million pounds held by the United States Enrichment

Corp. (USEC). The total inventory was held in several forms: 30 percent as natural uranium, 21 percent as natural uranium hexafluoride, 37 percent as low-enriched uranium hexafluoride, and 12 percent as fabricated fuel. Utilities held 58 percent of this total inventory; U.S. suppliers, 42 percent.

Both the United States and Russia hold inventories of highly enriched uranium (HEU) from nuclear weapons. The U.S. inventory is estimated to be equivalent to 370 million pounds of uranium, and that of Russia, 680 million pounds. Both countries have declared significant franctions of their HEU as excess to military need and announced plans to allow some of this excess material to enter the commercial market place. Some of the excess material is contaminated by other isotopes and is therefore unsuitable for civilian nuclear power fuel.

Russia has agreed to sell to the U.S. government the equivalent of 285 million pounds of uranium derived from HEU, and the U.S. government is finalizing a programmatic environmental impact statement for disposal of its own excess HEU.

INTRODUCTION TO MAPP AND NERC REGIONAL RELIABILITY

Introduction

The transmission and generation system is designed with networked alternate paths so that a single outage generally does not affect end-use customers. Reliability of the customer's electrical service is usually determined by the local distribution system into the home or business. Distribution systems typically do not have networked alternate paths so a nearby outage typically results in a customer interruption.

Discussion

In 1968 the North American Electric Reliability Council (NERC) was established to coordinate and promote communication about reliability of generation and transmission among the utilities. There are three major electric systems in the continental U.S.: Eastern, Western, and ERCOT (Texas). NERC has established guidelines that utilities have to follow in maintaining consistently reliable service for the transmission and generation system. NERC is organized into nine regional councils. The Mid-Continent Area Power Pool (MAPP) is the primary council that Nebraska utilities belong to. A small part of Nebraska is in the Western interconnection and belongs to the Western Systems Coordinating Council. The MAPP portion of Nebraska is interconnected with the Regional Council called Southwest Power Pool (SPP).

Nebraska utilities have been and are represented on the committees and board activities of NERC. In the past, NERC's authority has mostly relied on peer pressure from other utilities to meet the reliability standards established. They are working toward making these procedures mandatory with associated penalties for noncompliance. As open access of the transmission system occurs and the generation system is deregulated in response to Federal Energy Regulatory Commission orders 888 and 889, it becomes more and more important to insure reliability and stability of operation by standards that are mandatory.

MAPP operates in the Eastern Interconnection of the U.S. MAPP is a consortium of regional electric utilities and other parties. The MAPP organization performs four basic functions:

1) A regional reliability council, responsible for reliability of bulk electric system;
2) A regional transmission group, responsible for facilitating access to the bulk transmission system;
3) A power and energy wholesale market where electricity is bought and sold; and
4) A generation reserve shoring pool.

The amended MAPP Agreement recently approved by the FERC is resulting in new membership of non-electric utility organizations, e.g., power marketers. MAPP's functions of reliability, regional transmission, and power and energy marketing were specifically split out with the reorganization in 1996. These other functions can affect reliability and thus they are coordinated by MAPP as a whole.

MAPP has established and operates a wholesale market for the voluntary purchase and sale of electricity at market based rates. Participants buy and sell power and energy with other participants according to market service schedules. MAPP acts as the facilitator or contractor for these transactions. Firm, nonfirm, hourly, daily and longer duration transactions all occur to some degree.

The MAPP members in Nebraska have been very active on MAPP committees, task forces and working groups for many years. These committees and task forces look at the reliability criteria, the reliability of new additions, and reserve requirements to make sure there is consistency and compliance with the MAPP and NERC rules. NERC has previously relied on the regional councils to enforce their rules in addition to any specific rules that the regional council identifies as necessary for their region.

Transmission Reliability

The high voltage (115kV-230kV) and extra high voltage (345kV-500kV) transmission systems are designed to meet the reliability standards established by the North American Electric Reliability Council and MAPP. There are records kept of transmission line outages both for forced and for planned maintenance events. However, these records are not readily available in a format that generally allows comparison by specific groups of facilities such as a local region or state compared to the MAPP region or nation as a whole. Nebraska transmission systems meet the NERC/MAPP standards and are considered to be reliable systems. As electric loads grow and as generation is expanded or relocated the transmission system will have to be expanded to maintain reliability. Periodic maintenance is also required to maintain reliability.

The existing transmission system was designed and constructed to deliver electricity from generating facilities to load centers. Interconnections between utilities were intended for reserve sharing, electrical stability, frequency control and economic interchange. In a restructured competitive environment, the requirement to transfer power and energy will be dependent on the ability of transmission system to evolve and expand to maintain reliability.

Current MAPP Structural Issues

Two concepts evolving in the present deregulatory environment at the wholesale level due to FERC Order 888 are Regional Transmission Groups (RTG) and an Independent System Operator (ISO). An RTG is a voluntary group of transmission owners, users and other parties interested in coordinating transmission planning, expansion and use of facilities on a regional and interregional basis. An ISO is a new concept in the industry and would essentially manage the transmission network in such a way to allow open and equal access to wholesale buyers and sellers. Questions as to how exactly an ISO would accomplish that goal are evolving.

The MAPP Regional Transmisison Group (RTG) went into operation as of November 1, 1996. Concurrently, the MAPP Restated Agreement and revisions in membership went into effect.

This resulted in a number of other utilities not previously associated with MAPP, like St. Joseph Power & Light, Kansas City Power & Light, and Western Resources, to participate.

MAPP has also recently implemented (January 1997) an Open Access Same-Time Information System (OASIS). As required under FERC Order 889, the purpose of this system is to provide transmission customers and potential transmission customers with information about available transmission capability, prices and other information which enable them to obtain non-discriminatory open access transmission service. The information is made available in an electronic format, accessible via computer facilities.

A MAPP Task Force to study the Independent System Operator (ISO) concept has been meeting to develop an ISO proposal for the region. Nebraska utilities have representatives on this task force. A draft Restated Agreement to incorporate a MAPP ISO has been prepared. There has not been agreement to date to what extent the ISO would have authority over member utility transmission facilities or the number of control areas that will operate in the ISO frame work. Concern has also been raised whether Canadian provincial or U.S. public power utilities can legally allow an outside party, such as an ISO, to operate their transmission systems.

Under various concepts nationally, the ISO may assume operational control of the use of transmission facilities, administer a system wide transmission tariff applicable to all market participants and maintain short term system reliability. They also may engage in long-term planning. An important aspect is the ISO would govern the operational use of transmission facilities "independent" of the commercial interests of power suppliers who might be owners of the transmission facilities.

RELIABILITY AT THE CUSTOMER LEVEL

Reliability indices are calculated to measure the duration and frequency of electrical outages at the customer level. There is no single universally accepted methodology to track distribution reliability in the nation's electric utilities. Many utilities use some form of Edison Electric Institute (EEI), or Institute of Electrical & Electronic Engineers (IEEE) derived indices, but have different mechanisms of calculating the data. Some utilities do not record reliability data in any form or if they do, it is not made available outside the organization.

Two of the more commonly utilized indices are the System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). The SAIDI index is the "average time customers are interrupted" and implies a system average assuming all customers were interrupted an equal amount of time. The CAIDI index is the "average time to restore service to the average customer for a sustained interruption" or the average outage time for customers actually having an interruption. These two indices were included in the Nebraska survey conducted by NPA in December, 1996.

National Statistics

In a nationwide survey[1] sent to 100 private and public utilities in 1990 (49 responded) and 205 private and public utilities in 1995 (65 responded), IEEE compiled the following reliability statistics. (Note: Since the majority of the U.S. utilities are investor-owned, this survey would be weighted toward the investor-owned side.)

MEASURE	1990	1995
SAIDI (minutes/customer)	99.11	116.87
CAIDI (minutes/customer)	80.77	88.28

The SAIDI range of utility average responses in the 1995 survey varied from a low of 6.25 minutes to a high of 423 minutes. The CAIDI measure ranged from 11 minutes to 197 minutes in 1995. The relatively low response rate to the IEEE survey is indicative of either the data is not widely collected or if collected not shared outside the utility.

The American Public Power Association reported in a survey[2] of 138 public power utilities across the United States the following SAIDI measures according to the minimum time necessary before the utility classified the event as an outage. The weighted calculated mean for this group is 77 minutes average outage time per year.

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[1] IEEE Working Group on System Design, "A Nationwide Survey of Distribution Reliability Practices," 1996 IEEE Paper.

[2] APPA, Selected Financial and Operating Ratios for Public Power Systems," 1995 Data, Published February 1997.

1995		
MINIMUM OUTAGE DURATION	UTILITIES	SAIDI MEAN (MINUTES)
Less than 1 minute	26	87
1-2 Minutes	70	79
5 Minutes	15	110
15 Minutes	16	36
30 Minutes	6	12
60 Minutes	5	119

In reference to the above table, the SAIDI ratio will obviously be influenced by the way the utility records outages. If all other things were equal, a utility that does not record an outage of less than 30 minutes should have a more favorable SAIDI than one who records all but breaker operation outages (1 to 2 minutes or less).

In a report[3] commissioned by the APPA, Resource Management International (RMI) reported the following table in comparing public power systems to investor-owned systems for a SAIDI measure. The public power data was based upon an APPA annual survey while the investor-owned data was based upon a Theodore Barry & Associates Annual Electric Transmission and Distribution Best Practices Survey of over 30 investor-owned utilities.

ANNUAL MINUTES OF OUTAGE PER CUSTOMER					
DESCRIPTION	1991	1992	1993	1994	AVERAGE
Public Power SAIDIs	103	44	77	86	77.5
Investor-Owned SAIDIs	228	104	139	182	163.2

In a national 1995 based survey[4] conducted for rural electric utilities by the National Rural Utility Cooperative Finance Corporation (NRUCFC), the survey results reported were as follows:

[3]Resource Management International, "The Relative System Reliability of Public-Owned and Privately-Owned Electric Systems," prepared for American Public Power Association, December 1996.

[4]National Rural Utility Cooperative Finance Corporation, Data for National Outage Statistics, Special Report Request, January 1997.

ANNUAL MINUTES OF OUTAGE		
NATIONAL RURAL ELECTRIC SYSTEMS	**1995**	
	MEAN	MEDIAN
SAIDI (minutes/customer)	381.6	208.8

Nebraska Statistics

Of the NPA survey respondents, only 34 reported compiling and calculating the SAIDI reliability statistics for 1995. Of the reporting utilities, 31 were rural electric systems. OPPD, NPPD and LES were the only other utilities reporting. The balance either did not compile or did not report the reliability measures. The limited number of responses is not unique to Nebraska. The calculation is a data collection intensive process and most smaller utilities simply do not build the detailed data collection into their operational processes.

Only two utilities (OPPD and LES) reported a CAIDI measure. The arithmetic average is as follows:

[illegible]		
Nebraska (1995)	All Others	Rurals
SAIDI (minutes/customer)	58.6	166.5
CAIDI (minutes/customer)	56.7	NR

Discussion/Analysis

Although limited Nebraska data has been reported, the results for Nebraska utilities appears favorable when benchmarked against a comparable national source. The All Other Category data (OPPD, NPPD and LES) favorably compares to any of the investor-owned and public power national surveys. The Rurals data favorably compares to the NRUCFC national data.

The reliability difference between the Nebraska "All Others" category and Rural Systems would be expected. The primary reasons rural system reliability would be lower are the practical economics of construction given a low density of customers, predominantly overhead systems with extended miles of weather-related exposure and potentially long distances between service centers and damaged facilities when an adverse event occurs.

Nebraska utilities continue to make significant efforts to improve the reliability of power delivery in their transmission and distribution systems. Such efforts include:

1. Construction of new facilities to serve growing electrical demands by new and existing customers. Providing design contingency and backup capability in case adverse events happen.

2. Rebuilding and replacing older facilities enhanced design contingencies and utilization of better quality materials in construction, etc.

3. Some utilities are engaging in aggressive and proactive preventative maintenance practices such as additional troubleshooting patrols, infrared and thermovision inspections, substation monitoring equipment, dissolved gas analysis, alarming out-of-normal conditions, overhead line tree trimming, animal/squirrel protection, additional lightning protection, enhanced fault finding for underground cable failures, pole treatment applications, modification of maintenance practices (RCM), enhanced employee skills and training, etc.

4. Certain utilities are automating the transmission and distribution system through enhanced Supervisory Control of Data Acquisition (SCADA) systems, automated capacitor/reactor controls, automation of substation equipment and line switches, remote control from Control Center, automated mapping, employing state of the art telecommunication between facilities with fiber optic, wireless and power line carrier technologies and microprocessor based relaying for security, etc.

5. Some utilities are developing premium service options such as dual feeds, backup capacity in transformation, automated transfer schemes, etc.

A relatively new issue which impacts all Nebraska utilities is the quality of power delivered to its customers. Sensitive electronic equipment represents new challenges for ensuring high quality power and services. Despite utility controls on power delivery, and most power quality problems originate on the customer side, customers increasingly judge the quality of electricity by evaluating the performance on their own facility's equipment. The meter separating the utility from the customer equipment has become a "fuzzy" dividing point for responsibility for power quality problems. Certain Nebraska utilities are responding to customer concerns on power quality, helping to identify the origins of the problem, offering technical information and measurement, analytical and design tools, and monitoring hardware to address the power quality issue.

Nebraska utilities are also funding, through their EPRI membership, the development of new products and technology to address the power quality issues on both the utility and customer sides of the meter.

4.2.5 Other Considerations

A certain level of caution needs to be exercised in comparing reliability indices between utilities. A fundamental problem is that although utilities may report a SAIDI measure, they may be collecting and calculating the data differently. For example, some utilities do not record a sustained outage unless it is 5 minutes or more in duration; others utilize a one minute or less standard. Also, some utilities may report only distribution type outages but no transmission or subtransmission outages to customers, particularly if they do not own/operate those facilities. Some utilities exclude storm outages which affects the index. The industry, through IEEE, is working on standardizing definitions. Also the 1995 data is a one-year snapshot in time, that year may or may not be indicative of the long-term experience or certainly the future performance. A major ice storm or tornado could adversely impact a one-year result. A longer term historical average tends to even out fluctuations which may appear from year to year.

MAJOR INTERCONNECTIONS AND TIES

Introduction

An interconnection is an electrical system that operates interconnected and with generation units synchronized. There are three separate interconnected electrical systems, called Interconnections, in the continental United States: Eastern, Western, and The Electric Reliability Council of Texas (ERCOT).

Regional

Western Nebraska is on the western edge of the Eastern Interconnection and on the eastern edge of the Western Interconnection. The Eastern Interconnection is connected to the Western Interconnection by direct current (DC) ties across the interface. These two interconnections operate independent from each other except for power scheduled across the DC ties. Two DC ties are in Nebraska, one is at Stegall (100 MW), west of Scottsbluff, and one is at Sidney (200 MW). Flows across the DC ties are limited to the ratings of the ties. Flows on facilities of the network of alternating current (AC) facilities are determined by the physics of the system at the time. Such flows in an AC interconnection are much less controllable than flows across the DC ties. An AC interconnected system has very dynamic characteristics. The flows on the system will vary by what generation is on line, the transmission facilities available and the load. Changes in any one of these characteristics cause some change in the flows on the entire system. A change can occur very slowly such as a gradual load change or it can occur very quickly such as a loss of a line during a storm. The response of the system is planned so that it can sustain both of these types of changes.

Nebraska is interconnected to three of the nine North American Reliability Council (NERC) reliability regions in the continental United States (see writeup on NERC under System Reliability). It is interconnected with, and several Nebraska utilities are members of, the Mid-Continent Area Power Pool (MAPP) reliability region, a map of which is provided in Chapter 2. The States in MAPP that Nebraska has direct interconnections to are Iowa and South Dakota; specifically, four 345 kV lines, a 230 kV line and two 161 kV lines interconnect to Iowa and a 345 kV, two 230 kV lines, and four 115kV lines interconnect to South Dakota. These interconnections provide reliable backup and transmission paths for Nebraska generating units to make power transactions with other members of MAPP for economy or other purposes. These interconnections can be used to do transactions with any of the 70 MAPP members ranging anywhere from Manitoba Hydro in Canada, to North Dakota, to northern Minnesota, or to eastern Iowa. These interconnections also provide the path for the power from Western Area Power Administration (WAPA) to come to the firm power customers in Nebraska.

One Laramie River Station generating unit is interconnected to the MAPP region (Eastern Interconnections) and Nebraska, even though it is located near Wheatland, Wyoming. The two 345 kV lines from the plant are interconnections from Nebraska into Wyoming, however, the sole purpose of the lines is for delivery of power from Laramie River Station into the MAPP region.

Western Nebraska is interconnected with the Western Systems Coordinating Council (WSCC) reliability region. It is interconnected by the DC ties previously discussed. Also, a few western Nebraska AC facilities operate in the Western Interconnection. As mentioned previously some of the Laramie River transmission facilities are operated in the Eastern Interconnection and some are in the Western Interconnection. In addition, there are some additional facilities in Nebraska which operate on the Western Interconnection, including five 230kV lines, six 115kV lines interconnecting into Wyoming, Colorado and South Dakota. Most of the transactions into the WSCC from Nebraska utilities are across DC ties where capacity must be contracted for those transactions. An exception is Tri-State which has Nebraska transmission facilities and generation resources in the form of purchased power contracts with WAPA and Basin Electric Power Cooperative. The Municipal Energy Agency of Nebraska (MEAN) also has some Western Interconnection transactions that utilize facilities in Wyoming-Colorado area as well as western Nebraska.

On the south and southeast, Nebraska is interconnected to the Southwest Power Pool (SPP), particularly Kansas and Missouri. The interconnections to Kansas include a 345 kV line and a 161 kV line. There are two 345 kV facilities interconnecting into Missouri. Most of the transactions into the Southwest Power Pool are being conducted with Kansas City Power & Light, St. Joseph Light & Power, Associated Electric Power Cooperative, Sunflower Electric Cooperative, and Western Resources. Both nonfirm economy transactions and some firm capacity sales are being conducted at this time.

Nebraska

Throughout Nebraska there are multiple interconnections between the utilities in the state. These are used to provide adequate service to the customers' loads and to provide a reliable network for transferring power throughout the state and beyond. These interconnections are at voltages from 35 kV up to 345 kV. Generally, the voltages of 115 kV and above are used for both the transfer of power and delivery to load. Voltages below this level are generally used for delivery to a utility's customer loads.

POWER SYSTEM OPERATION

The goals of successful power system operation are reliability, adequacy, and economy through coordination, as demonstrated by Nebraska's regional council--MAPP. The processes and procedures for accomplishing successful operation are complex and many-faceted.

The power system consists of large and small generation plants that produce power using different fuels and possessing different operating characteristics. The customers, or users of electricity, are also of varying sizes and having differing loading characteristics for the generators to supply. Utilities tie the power plants with the customer loads by a network or system of transmission (high voltage), subtransmission (medium voltage) and distribution (low voltage) lines. The different voltages are connected together by transformers. Together generators, transformers, lines, and loads make up the basics of the power system.

To control the power system, computers located at utility dispatch centers are continuously engaged in monitoring the system with statewide metering and communication networks that carry information from remote points to the central dispatch computer and automatically back to the remote sites (generators, transformers, circuit breakers, etc.). The power system must be kept in synchronism and balance, otherwise generators and facilities will trip off-line.

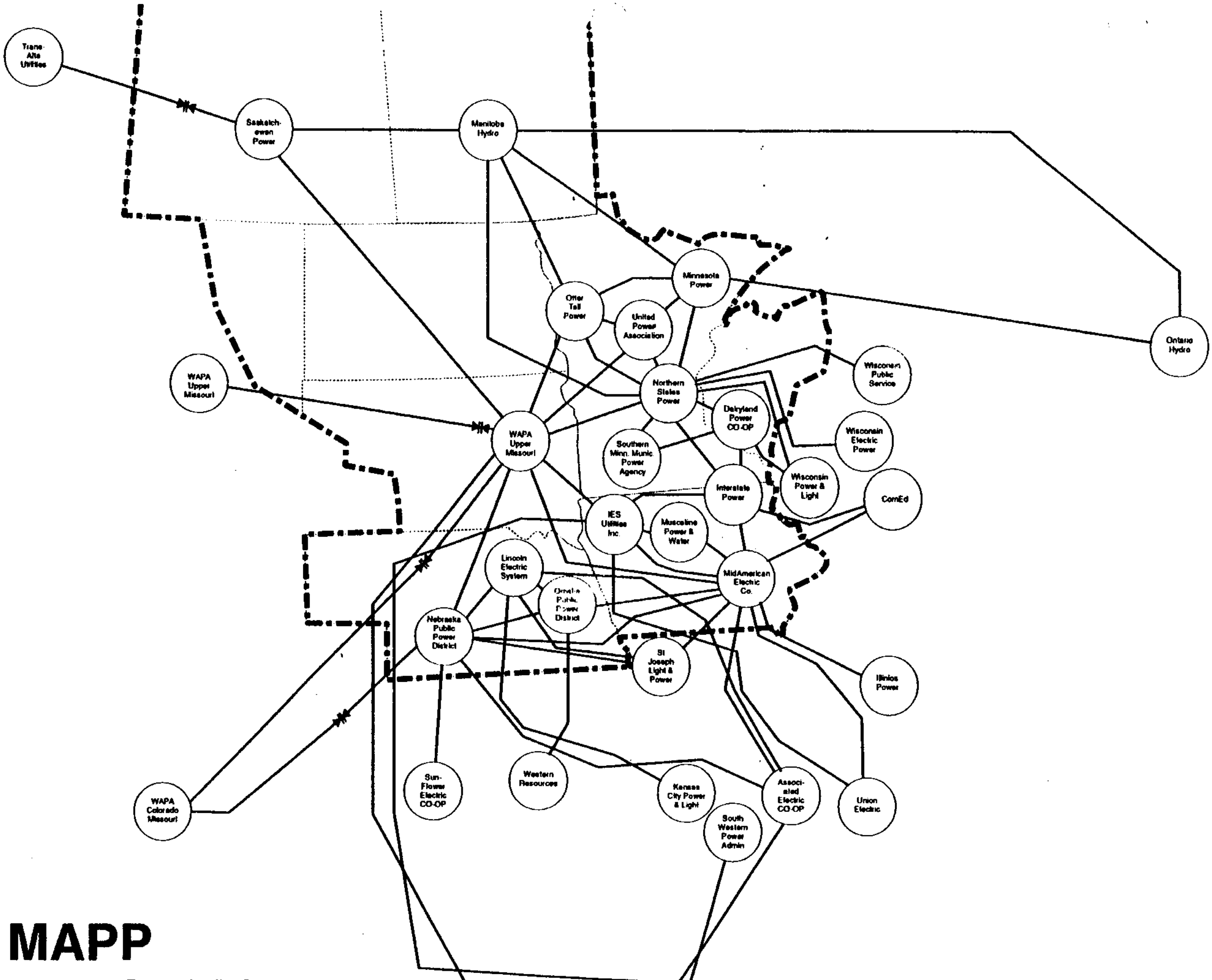
To organize this controlling process, the Interconnection is divided into control areas for which the host utility for the control area has certain responsibilities, such as continually maintaining the balance between generation and load (certain generators are ramped up or down continuously), arranging transmission paths for other utilities, carrying ready reserves to respond to emergency or contingency situations on the system, etc. Most of the power is of the alternating current (AC) type, because it can readily be transformed to different voltages for different purposes. AC power, though, cannot be easily controlled as to where it will flow. To prevent over loadings of system elements and provide public safety, circuit breakers at substations can be operated to disconnect from the system.

The control area operator (host utility) provides twelve interconnected operations services as part of its task: regulation, load following, energy imbalance, operating reserve-spinning, operating reserve-supplemental, system control, dynamic scheduling, reactive supply and voltage control from generation sources, real power transmission losses, and network stability services from generation.

In order to have a reliable and adequate system to operate, there must be ongoing planning and engineering studies to develop the best system for the task. On the transmission side, these studies include power flow, stability, transient analysis, line design, and relay coordination. The studies and engineering work on the generator side are just as involved employing most engineering disciplines.

Only with excellent planning and operations can the best system economy be achieved. Power pooling is a key element to achieving economy, which of course leads to complexity. By the coordination of power pooling, utilities support each other during emergencies and make available to each other their surplus energy production capabilities by engaging in power transactions (purchase/sales).

The Nebraska power system has successfully achieved the three goals of reliability, adequacy, and economy.



MAPP

Dynamically Controlled Generation

As of July 6, 1995

LOAD FORECASTING

Use of Load Forecasts

Load forecasting is an initial step in the integrated resource planning process. The utility plans for its system load, which is the aggregation of all of its customers' individual loads. System loads have two primary planning characteristics: peak demand and energy. Hourly system demand in megawatts (MW) is the average usage by the customers over an hour's time period, plus the transmission and distribution losses from the customer's usage point(s) to the utility generator point(s). System peak demand is the highest hourly system demand, usually meaning over a year's time but may be seasonally, monthly, or daily. System energy requirement in megawatt-hours (MWh) is the sum of the system hourly demands over the hours of interest, usually annual, seasonal, monthly, or daily.

The system peak demand in any year is important because it governs how much resource capability must be provided by the utility to satisfy its reliability obligations to other utilities and ultimately to its customers. This capability obligation to be planned and provided for is the system peak demand plus required reserves, which are essentially 15% additional to system peak demand. Energy requirements are also critical to integrated resource planning because they partially govern what type of resources will be most cost-effective.

Resources include both demand-side and supply-side resources. However, existing demand-side resources and their ongoing effects are normally netted out of forecasted load, as part of both the demand and energy forecasting processes. A capability vs. obligation depiction of all this, as shown and discussed in the Integrated Resource Planning section, represents capability as supply-side resources (generation capacity plus capacity purchases minus capacity sales) and obligation as required reserves plus system peak demand (customers' demands plus losses and demand-side resource effects netted out). If the utility is deficit by not having provided enough resource capability to cover its peak, then it must purchase capacity at a "penalty" price from the other utilities in the region according to established reliability agreements.

As part of these agreements and statutory requirements, Nebraska utilities submit planning and after-the-fact information to the Nebraska Power Review Board and to the Mid-Continent Area Power Pool (MAPP) which, in turn, sends the data on to the North American Electric Reliability Council (NERC), which compiles the data nationally for submittal to the U.S. Department of Energy. These reports are typically called Load and Capability Reports. When a report shows future projections it represents a brief summary of the utility's integrated resource plan.

Nebraska's Load Forecasting Methodology and Results

In Nebraska each utility, whether they are a member of MAPP or not, has the same requirement for providing 15% reserve capacity above their system peak demand and that requirement is individually applied utility by utility. Reserves are necessary to cover the real-life probability of equipment breakdown and to allow for maintenance of the equipment. Therefore, because compliance with capability requirements is enforced individually, load forecasts are also determined and required to be reported utility by utility. In a given year, all utilities may not peak in the same hour. The setting of the 15% reserve requirement has taken this diversity of loads into account. On the other hand, Nebraska utilities may all peak in the same hour of a year as did occur, for example, in 1984. Nebraska utilities are predominantly summer peaking and loads respond to heat and drought, especially air conditioning and irrigation. The primary baseline load level that is reported to MAPP is the 50% probable level. That is, there is judged to be a 50% chance that weather, economic and other factors may cause the actual loads to be higher than the forecast and a 50% chance that these factors will cause actual load to be lower than the forecast.

The above explanation of all utilities peaking at the same time refers to all "aggregated" utilities. For example, Nebraska Public Power District's wholesale requirements customers and retail customers together constitute one "aggregated" utility for purposes of load and capability reporting and thereby for integrated resource planning purposes. Because the vast majority of Nebraska load has been aggregated in this way, by a few power-supplying utilities (84% by the largest three and 98% by the largest eight utilities), there is very little remaining diversity between forecasted peak loads. This load diversity is usually considered to be 5% or less (and was zero in 1984). If there were to become a general movement across the region or country to reduce the capacity obligation by larger mergers that eliminate remaining diversity, it is likely the operating realities would dictate that reserve requirements be increased in order to maintain the same level of reliability as before the mergers.

The aggregated loads and smaller independent generating utility loads are shown (summer peak demands) separately for twelve utilities in Appendix E in the NPA IRP Coordination Report for a 20-year forecast period through 2015. The smaller Nebraska municipal generating utilities' load and capability forecasts are also shown consolidated. These independent load forecasts are developed separately by the utilities and are added non-coincidentally for a statewide total, in compliance with the reliability planning principles discussed above.

The utilities use various methods of load forecasting as particularly tailored for their utility's needs and technical resources. To varying degrees, all of the following load forecasting techniques are used by NPA utilities:

- trending (or time series), wherein forecast values are functions only of past values and/or time.

- econometric models, wherein forecast values are functions of economic and demographic variables such as population, income, etc.

- end-use models (or engineering models), wherein forecast values are functions of the amount (or stock) of energy-using appliances, equipment, or devices, and the amount of energy each appliance or device uses.

- hybrid models, which are most often combinations of the models described above, e.g., the use of econometric models to forecast an end-use component of load such as appliance saturations.

More than one forecasting technique typically is used by each utility because it creates models for each class of load. System energy is usually broken down into several classes of load, e.g., residential, commercial, industrial, irrigation, public authority, and street lighting. System peak demand is usually forecasted as one quantity rather than being broken down into separate customer classes. Most load in Nebraska is forecasted with econometric or end-use methods.

Both system energy and peak demand have been found to be dependent on many factors. Some of the most important factors for Nebraska utilities are population, family size, employment, income, general price indices, interest rates, fuel prices, electricity price, agricultural commodity prices, crop yields, number of appliances, types of appliances, appliance efficiency, conservation trends, weather, and customer incentive programs to encourage load changes.

Having considered these forecast factors, the Nebraska utilities' most recent statewide estimate of system peak demand is an average of 1.4% per year increase over the next twenty years. The range is 0.3% to 2.6% with urban areas typically growing at higher rates than rural areas. The system energy forecasts are not normally compiled on a statewide basis but are generally higher than system peak demand growth. This is partially due to demand-side management efforts and also due to the more rapid growth of higher load factor customers.

DEMAND SIDE MANAGEMENT—LOAD FACTOR IMPROVEMENT PROGRAMS

LOAD FACTOR IMPROVEMENT PROGRAMS	
SUBJECT	LR455 SURVEY SUMMARY RESULTS
• Commercial Lighting	4 utilities reported programs involving 1,242 participants with a total utility investment of about $250,000.
• Electric Grain Drying	4 utilities reported programs involving 8 participants.
• Electric Heat Promotions	113 utilities reported programs.
• Electric Lawn Mowers	3 utilities reported programs.
• Heat Pump Promotion	107 utilities reported programs.
• Heat Pump/Water Heater Promotion	83 utilities reported programs.
• Separate Demand/Energy Rates	102 utilities reported programs.
• Thermal Storage	2 utilities reported programs.
• Time of Use Rates	28 utilities reported programs.
• Water Heater Promotion	105 utilities reported programs.
• Ground Source Heat Pumps	1 utility reported a ground source heat pump system for 4 schools.

CUSTOMER-OWNED CO-GENERATION, BUY-BACK RATES, AVOIDED COST, NET BILLING

This section addresses the issue of utility purchases from consumer-owned generation facilities including the purchase rate and how it is determined. The section also includes customer-owned generation facilities of record.

Buy-Back Rates

The installation of cogeneration or renewable energy producing facilities are activities which increase the efficiency of energy usage and the conservation of scarce natural resources. Electric utilities in other states are often required to purchase energy from qualifying cogeneration or small power production (renewable energy) facilities in accordance with Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the rules issued by the Federal Energy Regulatory Commission pursuant to that section. See 16 USC Section 824a-3. For electric utilities subject to PURPA Section 210, it provides that rates for such a purchase (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) not discriminate against qualifying cogenerators or small power producers. In addition, Section 210 provides that no purchase can be required at a rate which exceeds the incremental cost to the electric utility of alternative electric energy. The term "incremental cost of alternative electric energy" means the cost to the electric utility of the electric energy which, but for purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. (The term "avoided cost" is frequently used interchangeably with incremental cost in the electric utility industry.)

In Nebraska, only generators approved by the Nebraska Power Review Board can sell electricity at retail. However, qualifying generators are allowed to sell at wholesale back to the utility at the utility's "avoided cost or incremental cost". In a survey of the larger power districts and municipals in the state, Nebraska's current practices use the "avoided cost" payment methodology for reimbursing generators. This practice aligns with the PURPA legislation. A discussion of the methodology used to calculate avoided costs for LES, NPPD, OPPD is described as follows.

Avoided costs are calculated by the three largest utilities in the state and for Tri-State G&T. The calculated costs include both an avoided energy and avoided capacity component. However, the avoided capacity portion is only applicable if the power purchased can be accredited in the Mid-Continent Area Power Pool (MAPP). The avoided capacity cost methodology includes the market value of capacity in the short-term and the avoided capital and fixed O&M costs of an appropriate future generating unit. This unit has been currently identified to be a combustion turbine for these utilities. Delaying the need for incremental generating capacity means temporarily avoiding its construction. Therefore, utilities are willing to pay an amount equivalent to the cost of purchasing capacity or constructing generation facilities. The levelized avoided capacity payments that the utilities would pay to a consumer wishing to sell capacity over a 20 year contract period are $1.72/kW-month for LES, $1.86/kW-month for NPPD and $1.87/kW-month for OPPD. These levelized payments represent the net present worth of the cost to purchase capacity in the short term and the avoided capital and fixed O&M of the next unit developed over the consumers contract term.

Tri-State G&T, because its Nebraska incremental capacity and energy needs are met by an all requirements power purchase contract with Basin Electric Power Cooperative (Basin), uses avoided costs provided by Basin. Tri-State has no avoided capacity costs because Basin and its members have sufficient generating capacity and long-term purchase power contracts in place to meet its members' needs until at least 2010. Since no new capacity is anticipated and therefore no costs are avoided, no capacity payments are provided to qualifying facilities.

Avoided energy costs are based on the projected average annual hourly system incremental energy costs, separated into on-peak and off-peak costs. These energy costs are based on existing and future unit operating characteristics such as heat rate, dispatch order, and forced- and planned-outage rates.

ESTIMATED AVOIDED ENERGY COSTS (1997)			
UTILITY	ON PEAK	OFF PEAK	AVERAGE
LES	1.32¢/kWH	0.89¢/kWH	---
NPPD	1.20¢/kWH	1.00¢/kWH	---
OPPD	1.27¢/kWH	1.15¢/kWH	---
Tri-State	---	---	1.05¢/kWH

Backup Rates

Some consumers install cogeneration and renewable facilities to offset or supplement energy purchased from the local utility. If the local utility does not have a backup charge, the energy produced has a value to the consumer equal to the retail price of energy. Some utilities bill a backup charge for consumers installing this equipment if the facilities are used to supplement or provide the entire energy requirements of the consumer. Backup charges collect investment costs utilities have made in generation, transmission, and distribution equipment that remain idle or are partially utilized while the consumers facilities are operated, but are fully needed during an outage of the consumer's generation equipment. If backup charges are not billed, the utility's remaining consumers must be charged to recover the costs of these investments. The three largest utilities in the state have some form of backup rate for these types of customers.

Net Billing

Some consumers have advocated using net billing to reimburse them for energy that is sold into the utility grid. Net billing refers to crediting or "running the meter backwards" for consumers who have their own electrical generators, such as wind and solar generators. When these consumers generate more electricity than they can use, their excess generation goes back into the utility system. Typically the greatest amounts of excess generation would occur in "off-peak" periods when the consumer's (and the utility's) loads are at a minimum, i.e. when the utility had the least need and the excess generation would have the least "value".

There has been some activity in recent years by interest groups in promoting a net billing law for Nebraska, e.g., LB 359 in the Natural Resources Committee in the 1995 Legislative Session and the identical bill, LB501, in 1997. This bill would have provided net billing payment at the retail price (full delivered cost) for wind or biomass generators up to 150 kilowatts in size. Because of the inability of the utility to accredit the capacity for these small consumer-owned generators within MAPP, the difference between "avoided cost" for net billing and retail price includes all generation capacity costs, transmission costs, and distribution costs.

In addition to this, there is the issue of added equipment costs for safety, interconnection, and system integration. Also, special metering and other equipment may be needed. If the utility pays for this equipment, then net billing not only is a loss of revenue, but also causes higher expenses. If the consumer pays for this equipment, then the installation of a generation system becomes less attractive.

Net billing regulations requiring utilities to pay for excess generation at retail prices are not common and may not be legal. The Federal Energy Regulatory Commission (FERC) ruled in January, 1995 that states cannot require utilities to pay more for electricity produced by PURPA-qualified generators than the utility's costs avoided by such purchases (Docket No. EL93-55). This is exactly what certain net billing programs would do; e.g. LB 501 noted above. Set at retail rates, the net billing price paid by Nebraska utilities would be approximately five times their avoided costs. If 10 MW of renewable energy facilities were installed and the energy purchased at the retail price, the additional cost to the utility consumers within the state is estimated to exceed $7 million (1996$), assuming the renewable facility operates for a 15-year period.[5]

Consumer-Owned Generation Facilities

There are 15 known non-emergency customer-owned generating facilities in Nebraska, with a total capacity of 29.19 Megawatts, that are used to provide energy or are used to reduce the utilities' peak loads. The following table lists the characteristics of this capacity by location, technology type, primary fuel and capacity. Not identified in this table are the significant number of emergency generating units installed by consumers to operate only when there is a loss of service from their local utility. These generators are typically small internal combustion units with high operating costs fueled by oil or natural gas and are not designed to operate continuously.

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[5]Nebraska Power Association "Statewide Integrated Resource Planning Coordination Report (1997-2016), October 1996.

[3]NPA LR455 Survey of the Electric Utilities in Nebraska.

As the table below indicates, there are eight cogeneration units and four renewable units within the state. These units have a total capacity of 18.03 MW and 4.05 MW respectively. The remaining three units are used to reduce load within the consumer's facility during the utility's peak period or emergency backup.

This 4.05 MW of renewable generating capacity represents about 0.1% of the total installed generating capacity of the Nebraska utilities. In comparison to national averages, renewable resources (excluding hydro) represent approximately 2% of all (utility and non-utility) generating capacity in the United States.[6] The great majority of renewable capacity is in the non-utility sector.

Location[3]	Technology	Primary Fuel	Capacity(MW)
Lincoln	Steam/Cogeneration	Coal	6.43
Lincoln	Internal Combustion	Bio-mass/Methane	0.81
Lincoln	Wind	N/A	0.01
Lincoln	Steam/Cogenerator	Natural Gas	1.50
Omaha	Internal Combustion	Bio-mass/Methane	1.88
Omaha	Internal Combustion	Bio-mass/Methane	1.35
Omaha	Internal Combustion/Cogeneration	Natural Gas	0.08
Omaha	Internal Combustion/Cogeneration	Natural Gas	0.12
Omaha	Internal Combustion/Cogeneration	Natural Gas	0.03
Omaha	Internal Combustion/ Cogeneration	Natural Gas	0.12
Omaha	Internal Combustion	Fuel Oil	1.25
Omaha	Internal Combustion/Cogeneration	Natural Gas	4.75
Omaha	Internal Combustion	Natural Gas	3.20
Scottsbluff	Steam/Cogeneration	Coal	5.00
North Platte	Internal Combustion	Fuel Oil	2.66
		Total	29.19

Parallel Operation of Consumer-Owned Generating Facilities

Parallel operation of generating facilities is defined as those generators that are interconnected with the utility grid and are simultaneously operating with the utility's generators

[6] Energy Information Administration, Electric Power Annual 1995 Volume II, DOE/EIA-0384(95)/2.

so that any excess power produced by the consumer can be utilized by the utility. Utilities interconnect with, and operate in parallel with, qualifying cogeneration facilities and small power producers in alignment with FERC and PURPA guidelines. However, many utilities in Nebraska also allow parallel operation of other consumer-owned generating facilities if the consumer meets specific technical requirements. These requirements are necessary to ensure the safety and reliability of both interconnected systems. These requirements also stipulate that the utility's other consumers shall not be adversely affected by the interconnection. Adverse effects include, but are not limited to, a reduction in service quality, higher cost of electricity, and utility capital expenditures for the interconnection.

A few utilities in Nebraska allow non-qualifying facilities to operate in parallel to reduce the generating capacity needed to meet peak demand requirements. These utilities offer special rates to essentially "lease" the consumer's generating capacity during these periods. The special rates available to these consumers are based on the "avoided costs" to purchase generating capacity and currently are not sufficient for a consumer to install generating units, just to take advantage of the special rate. Consumers who participate in these programs typically already have generating capacity installed for emergency conditions and are thus able to earn a return on normally idle facilities. Hospitals are typical consumers taking advantage of these special rates.

TECHNOLOGY DEVELOPMENT

The Electric Power Research Institute (EPRI)

The primary vehicle which electric utilities in the U.S. and in Nebraska conduct research and the development of new technology is the Electric Power Research Institute (EPRI). Created in 1973 by the nation's electric utilities, EPRI is one of America's oldest and largest research consortia with about 700 utility members. By pooling resources, a wider spectrum of projects are possible than if each utility was funding projects individually. Total funding for research, development and delivery in 1996 was $240.9 million. Nebraska utilities contributed a total of $3,461,368 in dues to EPRI in 1995. Nebraska utilities also contributed $607,410 for state and local research and $336,756 for other national research in 1995.

Nebraska electric utilities who are members of EPRI, along with their 1995 EPRI dues are as follows:

Lincoln Electric System	$	442,500
Nebraska Public Power District	$	613,806
Omaha Public Power District	$	1,150,062
Tri-State Generation & Transmission	$	1,255,000
TOTAL	$	3,461,368

These utilities also have staff members (35) who serve on various EPRI business unit advisory and governing boards. These members' input is vital to directing the research dollars to areas deemed most needed by their member utility.

Funding levels for EPRI member-supported research development and delivery programs are determined annually through an application of a formula based upon member sales of electricity. Member utilities may also fund specific research projects directly by providing specific project funding or co-funding. A variation of co-funding, called Tailored Collaboration, allows members to target a portion of their EPRI dues to eligible projects matched by general EPRI funding. Recent changes in funding arrangements allows utilities more flexibility in targeting their annual dues to specific business unit projects and targets.

A sampler of research and development achievements by EPRI taken from the 1995 Annual Report includes the following higher profile projects. Member Nebraska utilities, through their annual research dues contributed to these efforts and development.

Solar Energy - High-efficiency solar photovoltaic cells intended for bulk power applications.

Superconductivity - World's first functional use of high-temperature superconducting coil, being used in experimental direct-current motor.

National Lightning Detection Network - World's first real-time lightning-detection network, covering 3 million square miles of continental U.S.
Electric and Magnetic Field Effects - World's largest research program in electric and magnetic field effects.
Heat Pump - World's most efficient heat pump.
Coal Gasification - World's cleanest coal plant for power generation.
Fuel Cell - Largest phosphoric-acid fuel-cell plant for power generation.
Plasma Torch - Plasma torch for industrial uses, such as detoxifying arc furnace dust in steel-making process.
Nuclear Power - World leader in development of Advanced Light Water Reactor.
Clean Coal - Involvement in more than half the 39 projects co-funded under Department of Energy's Clean Coal Technology Program.
Acid Rain - Largest non-government sponsor of acid rain research.
Compressed Air Energy Storage - Nation's first CAES facility, for power generation and storage.
TL Workstation - First integrated software package for transmission-line analysis.
Clor-N-Oil Test Kit - First chemical test kit assessing concentrations of toxic polychlorinated biphenyls.
Fluidized Bed Combustion - Utility-scale circulating fluidized-bed boiler for power generation with variety of fuels.
Hydroelectric Power - Portfolio of techniques to relicense hydroelectric plants, including fish protection and dam safety.
High Sulfur Test Center - First integrated test facility for sulfur dioxide control options for coal plants.

4.5.2 Utilization of Evolving Technology by Nebraska Utilities

In addition to the research being conducted by EPRI, Nebraska utilities reported in the LR455 Survey actual utilization or active investigation of potential use or feasibility of use of various technologies. These efforts may be grouped into three general categories: generation technology, power delivery, and technology transfer to customers. The range of efforts and the number of utilities reporting research are indicated on the following pages.

TOPIC/SUBJECT	REPORTING UTILITIES
• **Generation Technology Utilization/Demonstration**	
Advanced Fuels	1
Advanced Turbines	0
Clean Coal	0
Fuel Cells	1
Hydro Revitalizations	3
Biomass	1
Environmental Air Emissions	4
Distributed Generation	0
Microturbines	1
Coal Gasification	0
Wind Generation	4
Photovoltaics	4
Waste to Energy	2
Environmental Water Quality	5
• **Power Delivery/T&D Technology Utilization/Demo**	
Power Quality	22
Predictive Maintenance	10
Reliability Centered Maintenance	4
Control System Enhancements	11
Adv. Control Systems (EMS/SCADA)	17
Premium Power Bus	1
Soft Switching Capacitors	4
Adv. Telecommunications	5
Electric Vehicle Demo	2
Electric Vehicles in Fleet	0
Substation Automation	17
Distribution Automation	9
Transmission Network Optimization	5
Adv. Diagnostic Equipment	11
Protective Relay Enhancements	10
Adv. Distribution Life Extension	5
Adv. Metering	25
Distribution Fault Locator	19
(Technology Transfer Below)	

Table 4-17	
• Technology Transfer to Customers	
Advanced Motors/Variable Frequence Motors	7
High Efficiency Lighting	12
High Efficiency Space Heating	17
High Efficiency Refrigeration	9
District Heating/Cooling	5
Power Quality	19
High Efficiency Cooling	20
High Efficiency Water Heating	21
Ground Source Heat Pumps	25

SYSTEM EFFICIENCY

Survey Results

The LR455 Survey collected a multitude of responses of engineering and operating mechanisms, methodologies and processes utilities were doing to meet the goal of improving efficiencies. The survey was only targeted to the larger and medium-size systems so the response numbers will be reduced compared to other results reported on other issues. Included in those responses were the following:

CATEGORY/DESCRIPTION		NUMBER OF ELECTRIC UTILITY RESPONDENTS EMPLOYING STRATEGY
TRANSMISSION & DISTRIBUTION RELATED		
1.	Purchasing low loss power/substation transformers to reduce energy losses	25
2.	Purchasing low loss line/distribution transformers to reduce energy losses.	27
3.	Voltage conversion - standardization and higher voltage for delivery efficiencies.	18
4.	Replacing undersized conductor for lower losses and increased capacity on existing facilities, i.e., delay additional facilities.	34
5.	Optimize line transformer loading for efficiency and minimize investment (including transformer load management).	26
6.	Optimize power transformers loading for efficiency and minimize investment.	25
7.	Phase balancing for efficiency, proper loading and magnetic field cancellation.	37
8.	Street light conversions for lower energy use.	28
9.	Metering calibration/electronic metering for accuracy, efficiency and enhanced information.	38
10.	Power factor improvements for system efficiency and reduce capital investment.	35
11.	Feeder sizing for lowering losses and improved efficiencies.	19
12.	Voltage optimization, i.e., tightening regulation of voltage to reduce capacity demands/improve power quality.	27
13.	Automatic and/or remote capacitor switching for voltage support and service quality.	25
14.	Feeder monitoring for enhanced information to optimize loadings and reduce capital investments.	20
15.	SCADA enhancement for improved information to operate the system for increased reliability and outage restoration.	22
16.	Distribution automation to enhance reliability, reduce labor and improve contingency responses.	10
17.	Distribution Planning Modeling so as to minimize investment and improve reliability.	15
18.	AM/FM to improve record keeping, information availability and assist in outage restoration.	17
19.	Employing substation life extension practices to minimize investment and extend life of existing facilities.	19
20.	Joint pole utilization to maximize utilization of infrastructure.	33
21.	Employing directional boring techniques to minimize restoration costs in undergrounding lines.	12
22.	Preventive maintenance enhancements such as thermal imaging for problem	32

	detection and minimize outages.	
GENERATION RELATED		
23.	Heat rate improvement in combustion of fossil fuels to improve efficiency of generating plants.	4
24.	Economic dispatch of generating units to lower power supply costs to customers.	5
25.	Fuel switching to take advantage of favorable fuel costs and increase flexibility of generating units.	4
26.	Capacity augmentation to enhance existing generation plants for additional capacity output and minimize new generation investment.	3
27.	Life extension of existing generation plants to minimize investment in new facilities.	7
28.	Preventive maintenance enhancement to extend life of generation units and minimize plant outages; such as thermal imaging for problems detection.	6
GENERAL		
29.	Optimum staffing and reengineering of work processes for efficient operations.	13
30.	Cost effective outsourcing of work for cost savings and best utilization of inhouse labor.	15
31.	Employing least cost planning strategies where both initial investment and ongoing O&M costs are evaluated in purchasing decisions.	30

The aforementioned topics represent some of many practices ongoing in the state's electric utility industry. In addition to the above, some utilities are engaging in enhanced telecommunications capability (fiberoptic, wireless, microwave, etc.), employing state of the art computerized technologies.

CHAPTER FIVE APPENDIX SECTION

(NO APPENDIX DATA FOR CHAPTER FIVE)

CHAPTER SIX APPENDIX SECTION

BACKGROUND INFORMATION AND DISCUSSION

THE PUBLIC UTILITY REGULATORY POLICY ACT (PURPA)

PURPA was passed in 1978 as part of the National Energy Act. The principal policy objectives of PURPA involved energy conservation, the development of equitable electricity rates and the development of new, small capacity generation, consisting of cogeneration and renewable power producers. PURPA established several standards which could be adopted, modified, or rejected by the appropriate state regulatory body. Examples of the standards set forth in PURPA include: 1) Cost of Service: Rates charged by an electric utility for providing electric service to each class of electric consumers must to the extent possible be designed to reflect cost of providing electric service to such class. 2) Declining Block Rates: The energy component of a rate would not decrease as energy consumption by the class increased unless the utility could show that its energy costs were decreasing prior amounts were sold. 3) Time of Day Rates: The rates charged by the utility within each class collective the time of day cost for providing service for a particular hour unless can be shown that such rates were not cost effective. 4) Seasonal Rates: Rates charged by a utility should be on a seasonal basis unless it could show that is not cost effective. 5) Interruptible Rates: Utilities were to offer industrial and commercial customers interruptible rates with the cost of interrupted service to those consumers. 6) Load Management Techniques: Utility would offer load management options which were cost effective.

The adoption of these standards was decided on a case-by-case basis by Nebraska utilities unless they were exempted from the act.

A quick review of current practices in Nebraska suggests the cost of service, seasonal rates, interruptible rates and load management techniques have received the greatest degree of implementation. PURPA was enacted at a time when energy costs were escalating and scarcities in oil and natural gas impacted the economy. Consequently, PURPA placed significant emphasis on the encouragement of energy conservation.

PURPA demonstrated an effort by the Congress to strike a balance between state and federal authority. The Federal Energy Regulatory Commission established the procedures for considering the proposed standards, but did not mandate a particular required outcome. PURPA provided authority for FERC to require transmission service in particular situations, however, such authority was never fully implemented or utilized.

Another major aspect of PURPA was the promotion of co-generation. The law encouraged co-generation and small power production and provided special privileges for those meeting those standards to become "Qualified Facilities" (QF's) resulting in significant growth of non-utility power generators. Electric utilities were required to purchase excess co-generated power from the QF's at the utilities "avoided costs" among other requirements. While the concept of purchasing at avoided costs appear reasonable, the implementation of these requirements in various states led to considerable controversy as to what the "true" avoided costs were if environmental externalities were considered. Of course, the determination of the cost of such externalities depended on whose perspective was adopted. Environmentalist groups and state regulatory agencies and legislatures in some states, with California being the most notable, established administratively determined avoided costs. This created a significant cost obligation to service contracts with numerous QF entities which in part has contributed to the high retail electrical rates in those states which are now considered one of the major "drivers" for utility restructuring and retail competition.

In states with low avoided generating costs and a limited number of industrial processes requiring or utilizing steam, such as in the upper great plains states, there has been minimal co-generation developed under PURPA. The general attention given nationally to cogeneration and renewable sources resulted in some small projects[1] in Nebraska for utilization of engine-generator cooling systems for heating water used in hotel, health club, and care-center applications. These small projects are not known to have generated electricity in excess of total site electrical needs. While some states experienced a significant amount of new non-utility generation as a result of PURPA, much larger amount of non-utility generation has been produced as a result of the Energy Policy Act of 1992.

Current Status of PURPA - There are also strong concurrent pressures for repeal of those sections of PURPA requiring utilities to purchase the output of QF's and instead allow the market to determine what the price should be for the output. Two bills were introduced in the 104th Congress to repeal Section 210 including S.708 Electric Utility Rate Payer Act by Senator Don Nickles (R-OK) and H.R. 2562 Rate Payer Protection Act by Congressman Cliff Stearns (R-FL). The intent of the bills was to focus on Section 210 and not to repeal the entire Act. Some arguments pro and con for repeal of PURPA are listed as follows[2]:

FOR REPEAL:

- PURPA is anticompetitive because utilities are required to purchase from QFs.
- PURPA's goals have already been achieved.
- Cogenerators and renewables have a foothold now and further promotion is unnecessary.
- PURPA has resulted in high prices to consumer because of QF contracts higher than avoid cost.
- EPAct provisions for Exempt Wholesale Generators render PURPA obsolete

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[1] Examples currently operating in Omaha include the a hotel, a fitness center, and an elderly care center

[2] DOE/EIA-0562(96) THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY: AN UPDATE - 1996, p-42

AGAINST REPEAL:

- Competitive market may erode goals for cogeneration, and renewables in particular.
- Need PURPA to deal with future energy crises.
- Incentives needed to conserve energy and use environmentally friendly fuels.
- QFs bring increased reliability and decrease need for large generating plants.
- Immediate repeal is a piecemeal approach and should be part of a comprehensive restructuring effort.
- PURPA is still needed to level playing field for nonutilities.

Summary - It should be noted that PURPA was introduced in part because of the oil embargo and rising costs of construction of new generating plants. In those states where adoption of excessively high avoided costs contributed to higher retail electric rates, there now exists as noted earlier strong incentive for electric utility restructuring and retail competition. There are also strong concurrent pressures for repeal of section 210 of PURPA requiring utilities to purchase the output of QF's as indicated in the reasoning in the pros and cons above and instead allow the market to determine what the price should be for the output.

In states such as Nebraska where the growth of cogeneration and renewables has been minimal, such pressures for PURPA repeal are not apparent. The presence of low-cost electrical generation in Nebraska has contributed to the presence of competitively low retail electric rates and to date, minimum residential and commercial customer pressure for industry restructuring and retail competition. Focus on maintenance of low rates has contributed to Nebraska electric utility reluctance to embrace renewable options until those options reach economic competitiveness with conventional generation alternatives. The role of renewables will be discussed elsewhere in this report, however, it should be noted from a national legislative perspective most restructuring bills introduced in Congress in 1996 and 1997 have strong renewable provisions which will impact all or most electrical generators and which will probably exceed the renewable accomplishments of PURPA since enactment in 1978.

THE ENERGY POLICY ACT OF 1992 (EPACT)

The Energy Policy Act of 1992 contained a total of thirty sections.[3] The section of specific focus at this time is Title VII - Electricity which has been the driving legislation leading to regulatory orders by the FERC and the basis for new expansion of the independent power industry since 1992. It is important to note that the scope of EPAct is far broader than Title VII and may lead to future legislation and regulation in areas beyond restructuring of the electric utility industry. Therefore in order to outline the broad scope of EPAct, the following is a listing of all sections for general information:

TITLE	DESCRIPTION
I	Energy Efficiency
II	Natural Gas Pipelines
III	Alternative Fuels - General
IV	Alternative Fuels - Non Federal Programs
V	Replacement fuels, Alternative Fuels and Alternative Fueled Vehicles
VI	Electric Motor Vehicles
VII	**Electricity**
VIII	High-Level Radioactive Waste
IX	Uranium Enrichment Corporation
X	Remedial Action and Uranium Revitalization
XI	Uranium Enrichment Health, Safety, and Environment Issues
XII	Renewable Energy
XIII	Coal
XIV	Strategic Petroleum Reserve
XV	Octane Display and Disclosure
XVI	Global Climate Change
XVII	Additional Federal Power Act Provisions
XVIII	Oil Pipeline Regulatory Reform
XX	General provisions: Reduction of oil vulnerability
XXI	Energy and Environment
XXII	Energy and Economic Growth
XXIII	Policy and Administrative Provisions
XXIV	Non-Federal Power Act Hydropower Provisions
XXV	Coal, Oil, and Gas
XXVI	Indian Energy Resources
XXVII	Insular Areas Energy Security
XXVIII	Nuclear Plant Licensing
XXIX	Additional Nuclear Energy Provisions
XXX	Miscellaneous

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3 Public Law 102-486-OCT.24, 1992 - ENERGY POLICY ACT OF 1992

Title VII of the EPAct contains the following primary subtitles which will be discussed as part of this report although the primary focus will be on Subtitles A and B. Subtitle C protects the authority of state and local authorities in regards to environmental protection or siting of facilities.

Subtitle A	Public Utility Holding Company Act[4] (PUHCA) Amendments
Subtitle B	Federal Power Act - Interstate Commerce in Electricity
Subtitle C	State and Local Authorities

(1) **Subtitle A** - The intent of the amendments to PUHCA is to exempt current and prospective independent power producers from certain restrictive provisions of PUHCA by creation of a category defined as an Exempt Wholesale Generator (EWG). The EWG's will also have fewer restrictions under the Federal Power Act. This subtitle also prevents independent power producers which are affiliates (owned by holding company for example) of an incumbent regulated electric utility to engage in "self-dealing" transactions. Given the access to the transmission system for wholesale transactions provided by subtitle B, the EWG is provided the opportunity to compete in the wholesale electricity market.

This section of EPAct allows independent power producers to build and purchase or have shared ownership in electric generating facilities without becoming subject to PUHCA. The subtitle also contributes to the possibility for incumbent electric utilities to divest part or all of their generating facilities to create independent corporations or subsidiaries without those corporations becoming holding companies under PUHCA.

Due to this new class of EWG's and in large part because of declining gas prices and improved gas turbine efficiencies, there has been a significant expansion of new low cost natural gas generation throughout the country for peaking capacity purposes, and in some cases, this new generation is lower in cost when compared to other base and intermediate load resource alternatives when using combined cycle technologies.

From a Nebraska perspective, public power districts are currently prevented by state statutes[5] from selling their generating assets to private entities.

(2) **Subtitle B** - Following are brief discussions of the key sections of Subtitle B. The relevant provisions of Subtitle B are implemented by FERC Orders 888 and 889 and will not be discussed separately in this report.

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4 The Public Utility Holding Company Act of 1935 was in part enacted to address the market power and securities abuses of electric utility holding companies

5 Revised Nebraska Statutes 70-657, Public Power Districts; facilities and property; alienation to private entities, prohibited; exception

Section 721 Amends Section 211 of the Federal Power Act to allow any federal power marketing agency or any other person generating electric energy for sale for resale (wholesale) to apply to the FERC for an order requiring a transmission owner to provide transmission service to the applicant, including enlargement of transmission capacity if necessary. This section further states that the FERC may issue orders under section 212 and is prevented from issuing such orders if reliability of electric service is threatened by such.

Section 722 outlines authority and conditions for rates, charges, terms, and conditions for wholesale transmission services, contains savings provisions, respects anti-trust laws, prohibits orders inconsistent with retail marketing areas, prohibits mandatory retail wheeling orders (by the FERC) and sham wholesale transactions, contains a special section for TVA and BPA.

Section 723 addresses information requirements, response required to good faith transmission service requests, addresses information on transmission capacity and constraints.

Section 724 provides regulation of sales by EWG's involving associated or affiliated transactions.

Section 725 outlines existing penalties not applicable to transmission provisions and adds penalties applicable to transmission provisions.

Section 726 provides additional definitions of transmitting utility, wholesale transmission services, and exempt wholesale generator including clarification of terms to include any municipality after state agency in Section 3(22) of the Federal Power Act.

The provisions of Subtitle A and B of the Energy Policy Act of 1992 currently being implemented primarily by the FERC through Orders 888 and 889 and subsequent orders will significantly change the wholesale electric landscape of the electric utility industry by mandating open access for transmission and setting in place mechanisms for creating a competitive wholesale electrical market. Although there are several key provisions in EPAct, the most significant insofar as promoting competition in the generating sector of the industry has been the opening of the transmission grid. The open access provisions of EPAct are expected to provide for a more competitive wholesale generation market with a greater number of market participants. The specific requirements for providing open transmission access are being implemented through FERC Orders 888 and 889 which are discussed in greater detail in Section 6-2.

Summary - The purpose of EPAct Title VII was to open and expand the wholesale transmission market and the FERC is specifically prevented from ordering retail wheeling in Section 722 of Title VII Subtitle B. In debates over the past few years between the FERC and state regulators and others, the FERC has suggested that it has regulatory authority over the rates, terms, and conditions of unbundled retail wheeling service. As a subsequent section on Identification and Summary of Bills Introduced Recently will indicate, retail wheeling has taken on a national debate of its own and FERC authority may be expanded to include jurisdiction over the rates, terms, and conditions of unbundled retail wheeling service in the states which mandate retail competition or in federally-mandated retail competition situations and perhaps FERC may eventually acquire the authority to order retail wheeling transmission service.

PROPOSED FEDERAL LEGISLATION

As an example of proposed federal legislation and the issues being addressed, major provisions of Senator Bumpers (D-AR) Bill S. 237 regarding electric utility deregulation are summarized as follows:

Title I Retail Competition

Mandatory Retail Access: Provides a December 15, 2003 deadline mandating access for retail purchase of electricity by all electricity consumers. Also included is a December 15, 2003 access deadline for all persons seeking to sell retail electric energy through local distribution and retail transmission facilities.

Prior Implementation: Provisions allow for states to require retail electric competition prior to the December 15, 2003 federal deadline. Provisions also include grandfathering for state legislation enacted prior to January 30, 1997 that requires retail electric competition on or before December 15, 2003.

State Requirements/Authority: Provisions allow states to regulate retail electric energy suppliers as necessary to promote the public interest including requirements for system reliability and information regarding energy suppliers. States may also continue to regulate local distribution and retail transmission service provided by retail electric energy providers.

Stranded Cost Recovery: Includes provisions for state regulatory authority to calculate stranded costs associated with implementation of retail competition if the utility was subject to state regulation prior to the date of enactment of this legislation. If the state does not calculate the stranded costs, the Federal Energy Regulatory Commission must require the utility to sell its generating facilities for the purpose of calculating stranded costs. Non-regulated utilities such as those in Nebraska may calculate stranded costs by one of two methods: 1) determine the level of the utility's legitimate, prudently incurred and verifiable investments in generating assets and related regulatory assets that can't be mitigated, or 2) sell all generating facilities and then subtract the revenue received from the book value of the assets sold. Once stranded costs have been determined, the utility is entitled to recover such costs over a reasonable period of time through a non-bypass able Stranded Cost Recovery Charge imposed on its distribution and retail transmission customers.

Multistate Utility Company Stranded Costs: Provisions specify that customers served by utility companies operating in more than one state either directly or through an affiliate are only responsible for stranded costs arising from retail electric competition in the state they reside. Provisions also include creation of regional boards to determine legitimate stranded costs for utilities serving customers in more than one state.

Universal Service: Provisions include obligation of electric energy provider to provide access to competing retail electric energy suppliers by December 15, 2003. Reasonable compensation for provider access is also provided for and states may impose a non-bypass able Universal Service Charge on distribution and retail transmission consumers to help pay for the retail electric energy provider's compensation.

Renewable Energy (includes electricity generated from solar, wind, waste, biomass hydroelectric and geothermal resources): Provisions include an annual requirement of 5 percent renewable energy beginning in calendar year 2003 for each retail electric energy supplier. Thereafter, the required annual percentage for each supplier shall be 9 percent beginning in calendar year 2008 and 12 percent beginning in calendar year 2013. Provisions have also been included which provide electric energy suppliers with the option of purchasing credits from retail electric energy suppliers that sell renewable energy in excess of the minimum requirements. Provisions also require preparation and submittal of annual reports to FERC to verify compliance with the above requirements.

Transmission: Provisions include FERC requirement to issue rules by January 1, 2002 applicable to its and various Regional Transmission Boards' oversight of the Independent System Operators. These rules are intended to promote transmission reliability, efficiency, and competition among retail and wholesale electric energy suppliers.

Cross-Subsidization: This legislation does not permit retail electric energy providers from recovering in its distribution and retail transmission rates any costs associated with unregulated activities.

Mergers: Includes provisions pursuant to the Federal Power Act for electric utility mergers and mergers of electric utilities and natural gas utilities. FERC would have authority to determine if these mergers are in the "public interest."

Market Power: Includes provisions providing FERC authority to take such actions as necessary to prohibit retail electric energy suppliers and providers from using their control of resources to inhibit retail and wholesale electric competition.

Nuclear Decommissioning Costs: Provisions allow that utilities owning nuclear generating units prior to the enactment date of this legislation are entitled and obligated to recover from their customers, costs necessary to fund decommissioning.

Tennessee Valley Authority (TVA): Provisions allow for sale of wholesale and retail TVA electric energy outside its service territory and allows for TVA customers to buy energy from other suppliers. The effective date for this provision is December 15, 2003 or an earlier date is so decided by TVA.

Enforcement: Provisions allow that any person may bring an action to enforce provisions of this legislation in the appropriate Federal district court. Any person seeking redress from any action taken pursuant to this legislation by a State Regulatory Authority, FERC, or regulatory board shall bring such action in the appropriate circuit of the U.S. Court of Appeals.

Title II Public Utility Holding Companies

Public Utility Holding Company Act of 1935: Provisions include repeal of this Act effective one year from the date of enactment of this legislation.

Exemptions: This title (Title II) does not apply to federal or state agencies (including any political subdivision of a state) or foreign governmental authorities not operating in the U.S.

Title III Public Utility Regulatory Policies Act (PURPA)

Facilities: Provisions specify that PURPA shall not apply to any facility which began commercial operation after the effective date of this legislation.

Study: Provisions require EPA to prepare and submit to Congress by January 1, 2000 a report assessing the impact of utility deregulation on public health and the environment. This report will also include recommended changes to federal law, if any are necessary, to protect public health and the environment.

INDUSTRY DEREGULATION AND RESTRUCTURING IN OTHER STATES

A. Comparison of Enacted Restructuring Legislation in CA, NH, PA, and RI

This subsection contains a comparison of legislation adopted in the states of California[6] (CA), New Hampshire[7] (NH), Pennsylvania[8] (PA) and Rhode Island[9] (RI) for implementing customer choice or retail competition. . Also included in the comparison are positions prepared by the American Legislative Exchange Council[10] (ALEC). At the end of each basic issue are comments prepared to reflect potential Nebraska issues that should be considered in the Phase II Study.

(1) Customer Choice or Retail Competition
(2) Disaggregation/Divestiture
(3) Open Access to Transmission and Distribution Facilities
(4) The "Level Playing Field" concept
(5) Reciprocity Among Suppliers Within States
(6) Reciprocity Between States
(7) Recovery of Stranded Costs
(8) Obligation to Serve
(9) Miscellaneous

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6 CALIFORNIA - Assembly Bill 1890 (AB 1890) (Stats. 1996, Ch. 854) - Governor Wilson signed this legislation on September 23, 1996, codifying many of the decisions made by the California Public Utilities Commission (CPUC) in its December 1995 order restructuring the state's electric utility industry.

7 NEW HAMPSHIRE - HOUSE BILL 1392, approved May 21, 1996. - Governor Merrill signed this bill into law on May 21, 1996, and New Hampshire became the first state to adopt comprehensive industry restructuring legislation. The legislation directed the PUC to develop and implement the statewide restructuring plan. The PUC issued its preliminary plan on September 10, 1996. Hearings held in January, 1997, will provide opportunity for input to the proposed plan. The final order is due February 27, 1997.

8 PENNSYLVANIA - ACT 184, 1996 Pa. Laws 184 - - Governor Tom Ridge signed the bill into law on December 3, 1996, mandating a major restructuring of the state's electric utility industry and a state-wide phase-in of retail access. Pennsylvania became the fourth state in the country to legislate a state-wide phase-in of customer choice for electricity.

9 RHODE ISLAND - THE UTILITY RESTRUCTURING ACT OF 1996. BILL 96-H 8124 - Governor Almond signed the final bill into law on August 7, 1996. Rhode Island became the second state to adopt comprehensive restructuring legislation.

10 AMERICAN LEGISLATIVE EXCHANGE COUNCIL (ALEC) - On December 4, 1996, the ALEC Board of Directors formally approved as official ALEC policy model state legislation that would restructure the electric power industry. This model has been provided to state legislatures by ALEC.

(1) Customer Choice or Retail Competition

ALEC: § 4(A) - Full customer choice by thirty-six months after legislation is enacted

§ 6 - Retail customer choice no later than December 31, 2000

CA: Chapter 2.3 - ELECTRICAL RESTRUCTURING, Article 1. § 330(l)(4) and § 330 (n) and § 365(b) - First phase of Direct Access will begin no later than January 1, 1998; minimum phase in schedule is provided to ensure all customers have Direct Access January 1, 2002. Publicly owned utilities which elect to have retail wheeling must start the phase in two years after IOUs.

NH: Chapter 374-F:4 - Retail wheeling for all customer classes at earliest possible date, but not later than July 1, 1998. Customers should be able to choose among electricity suppliers and options such as levels of service reliability, real-time pricing and "generation sources, including interconnected self-generation."

PA: Sections 1,4 of Act 184, 1996 Pa. Laws 184, amending the Associations Code and the Public Utility Code - Choice of an energy provider for all customers of electric cooperatives and PUC jurisdictional electric utilities will be phased-in and completed by the year 2001. Phasing of retail choice will begin with mandatory pilot programs filed with the PUC by April 1, 1997, each pilot must last at least one year and apply to 5% of peak load for each customer class in 1997. Eligibility increases to one-third of each utility's customers in 1999, followed by an additional third each in the following two years. PUC is given flexibility to extend or condense access schedule as it sees fit.

RI: One-year phase-in of retail wheeling to be completed by July 1, 1998. § 39-1-27.3©

Comments for LR 455 Phase II on Customer Choice/ Retail Competition

The States of California, New Hampshire, Pennsylvania, and Rhode Island have been the first states to adopt customer choice/retail competition. Except for Pennsylvania, one of the common driving factors has been high retail rates. Unknown at this writing is the probably of a federal mandate for customer choice or what the pace will be for other states to move to customer choice without a federal mandate. Many states including Nebraska have elected to conduct studies of their electric utility industries to determine the need for restructuring and the need for introduction of retail competition in some form.

It is difficult to overlook the looming prospect for federally mandated retail customer choice when the content of recently introduced legislation in the U.S. Congress is reviewed (such as that shown in section 6.1 of this report). Timing on a major industry restructuring is very important, in particular for states such as Nebraska with consumer-owned utility assets at risk and the potential for a competitive retail electric market to overlook or ignore rural and low income customers in favor of larger, higher load factor customers in more densely populated urban areas.

Whether or not to have retail customer choice and if so, when, could be one of the fundamental element of the Phase II study.

(2) Disaggregation or Divestiture

ALEC: § 8 - Public Service Commission (PSC) shall require all existing electric utilities operationally and/or financially to separate electric generation, transmission and distribution assets and operations.

CA: AB1890 favors, but does not mandate, the divestiture of generation assets. The PUC issued a voluntary divestiture proposal in a Preferred Policy Decision by which utilities would divest at least 50% of their fossil-fuel generation assets to mitigate market power problems. Divestiture may also occur under the rate reduction bond process.

NH: Section V, Preliminary Plan, PUC DR 96-150, September 10, 1996 - Functional Unbundling is required; the PUC may require corporate Unbundling. The Preliminary Report by the PUC states that divestiture of generation assets is the most accurate way to determine their worth and thus establish stranded investment.

PA: § 4 of 184 - The Commission may permit, but shall not require, a regulated electric utility to divest itself of facilities or to reorganize its corporate structure. There is sufficient authority given to the Commission in Act 184 to require functional Unbundling of jurisdictional electric utilities. There is nothing in Act 184 that would give the Commission authority to require the functional Unbundling of electric cooperatives or municipalities that voluntarily offer retail choice.

RI: § 39-1-27 Electric distribution companies are required to file proposed restructuring plans with PUC by January 1, 1997. The plan must include proposals for transferring the ownership of generation, transmission and distribution facilities to separate affiliates of the distribution utility and Unbundling of rates. At least 15% of non-nuclear generation must be sold or otherwise transferred. Such sales are for the purpose of establishing value.

Comments for LR 455 Phase II on Disaggregation or Divestiture

The consequences of disaggregation or divestiture as part of a comprehensive industry restructuring program should be evaluated in Phase II. . Current statutes[11] prohibit the sale of public power district assets to private companies. The most obvious assets to be divested could be electrical generation and transmission assets. Questions must be asked such as to what would be the receiving agencies for divestiture, public or private generating companies, or simply a shifting of ownership or control to a form of public power holding company. Also to be studied would be the advantages and disadvantages of disaggregation or divestiture in achieving effective competition. Would the state's consumers be better off if any segment of the consumer-owned industry assets were spun off in order to develop a competitive wholesale, forestalling the requirement to provide retail competition and break up the existing retail service area arrangements in the state? Phase II could consider the ramifications of disaggregation and divestiture as it pertains to consumer-owned assets.

(3) Open Access to Transmission and Distribution Facilities

ALEC: § 9 - Owners, operators and providers of transmission and distribution facilities and ancillary services and other services available to any buyer or seller are required to provide access to those facilities on a nondiscriminatory and comparable basis.

CA: IOU transmission owners must submit control of their transmission facilities to an ISO. Publicly owned are encouraged to do the same.

NH: § 374-F:4(III) - Nondiscriminatory open access to the electric system for wholesale and retail transactions should be promoted and the PUC should monitor T&D services to ensure that no supplier has an unfair advantage. All utilities subject to the jurisdiction of PUC shall be required to submit compliance filings, which shall include open access tariffs and such other information as the PUC may require, no later than June 30, 1997.

PA: Sections 1 & 4 of Act 184 - All electric cooperatives and jurisdictional electric utilities in PA shall provide electric suppliers licensed by the Pennsylvania Public Utility Commission open and nondiscriminatory access to their transmission and distribution facilities.

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11 Rev. Nebraska Statutes - Chapter 70 Article 646: Public Power District; alienation to private power producers, prohibited; exceptions

RI: The law requires transmission companies to file open-access transmission tariffs with FERC and distribution companies to file delivery tariffs with the PUC. Transmission and distribution companies must offer service on comparable, non-discriminatory prices and terms. § 39-1-27(a)

Comments for LR 455 Phase II - Open Access to Transmission and Distribution Facilities

The concept that utilities, both public and private, which engage in competition utilizing the transmission and distribution assets of other utilities should provide reciprocity access to their own transmission and distribution lines on a comparable and nondiscriminatory basis is an important equity and fairness issue. FERC orders recently clarified require non-jurisdictional utilities to provide reciprocal, comparable services to that received from others.

In some state legislation enacted, if opt-out provisions are available and elected, a non-jurisdictional utility may not be required to provide retail wheeling services.

Nebraska's open-access[12] legacy for the past 30 years has allowed wholesale competition to flourish such as in the evolution of the Municipal Energy Agency of Nebraska and Nebraska Municipal Power Pool in competition with other public power wholesale agencies. Phase II could evaluate the effectiveness of this wholesale competition and further address the evolution of this wholesale competition in view of the EPAct and FERC Orders 888 and 889 (series).

(4) The "Level Playing Field" Concept

ALEC: **REGULATORY**

§ 15(A) - Municipal and state electric service providers and electric member cooperatives shall be treated as utilities for purposes of this act.

§ 15(B) - All distribution services providers shall be subject to jurisdiction of PSC.

§ 13(B) & (D) - PSC shall establish rates for unbundled local distribution services and shall also have jurisdiction over all aspects of transmission rates and services not subject to exclusive jurisdiction of FERC.

12 Rev. Nebraska Statutes, Chapter 70 Article 625.02 Electric transmission facilities and interconnections, defined; policy of the state

TAX

§ 15(B)(1) - All distribution services providers shall be subject to uniform tax obligations.

§ 22(H) - Comparable state and local taxation burdens should be placed upon all market participants.

CA: AB 1890 does not attempt to "level the playing field".

NH: § 374-F:3 VII says " . . . that the rules that govern market activity should apply to all buyer and sellers in a fair and consistent manner." The PUC recommends in its preliminary report that any taxes levied on market participants "be competitively neutral". § VII(G)(1). It is not clear if this includes municipalities.

PA: REGULATORY

Municipal utilities and electric cooperatives that choose to serve retail customers in a PUC jurisdictional electric utility's certified service territory will be subject to the jurisdiction of the PUC. (SEE §2 of Act 184, amending the Title 66, Public Utility Code, § 2809).

TAX

Act 184 is designed to result in tax neutrality. Act 184 requires electric cooperatives and municipal utilities that serve retail customers in a jurisdictional electric utility's certified service territory to pay those taxes normally imposed only on a jurisdictional electric utility. (supra.) Interestingly, jurisdictional electric utilities serving customers within a municipality or electric cooperative service territory are not subject to the taxes they would normally be subject to.

RI: Not addressed in the legislation.

Comments for LR 455 Phase II - The Level Playing Field Concept

Considering the all consumer-owned electric utility aspects of Nebraska and the lack of a public utility commission for electricity, the level playing field concept is applicable to the current electric utility structure in regards to intra-state competition because of the different enabling legislation for public power districts, municipal utilities, joint-action agencies and electric membership cooperatives.. The issue should be considered in Phase II to provide a more level playing field within the state and to determine if any adjustments are appropriate.

(5) Reciprocity Among Suppliers within States

ALEC: § 10 - All intrastate owners and operators of transmission and distribution facilities shall have comparable and reciprocal access to the transmission and distribution customers of other transmission and distribution facility owners and operators.

CA: The bill sets an instate reciprocity requirement among investor-owned and publicly owned utilities.

NH: § 374-F:4(IX) - Electricity suppliers shall be eligible to compete, subject to limitations established by the PUC, for open access customers only if affiliated utilities file comparable open access transmission and distribution rates with the FERC or the PUC, or both as appropriate.

PA: Section 4 of Act 184, amending Title 66 to add a new § 2805(B)(2) - No electric cooperative or municipality which distributes electricity to end-use customers may utilize the transmission or distribution system of an electric utility regulated by the commission for the purpose of supplying electricity to an end-use customer unless the electric cooperative or municipality provides open and nondiscriminatory access and allows other electric generation suppliers to utilize its facilities.

RI: All distribution utilities within the state have access to all customers. No specific mention of customers of municipal utilities.

Comments for LR 455 Phase II - Reciprocity Among Suppliers within States

Reciprocity at the wholesale level in Nebraska between the state's power agencies with transmission already exists as part of the mandatory transmission service requirement above 34.5 kValthough not specifically mentioned in the statutes applicable.

The Phase II study could review customer choice restructuring plans in the above states in regards to reciprocity and its relevance to Nebraska.

(6) Reciprocity Between States

ALEC: § 9(C) - The PSC shall establish by regulation and consistent with federal law reciprocal rights for transmission and distribution access between corporations located within the state and those located outside the state.

CA: Reciprocity is not expressly required.

NH: Not required. 374-F:3(XIII) states that " . . . while it is desirable to design and implement a restructured industry in concert with the other New England and northeastern states, New Hampshire should not unnecessarily delay its timetable."

PA: Reciprocity is not explicitly required from electric generation suppliers located outside of the Commonwealth of Pennsylvania. The Commission may have been given sufficient regulatory authority in Act 184 to require by regulation that out of state electric generation suppliers grant reciprocity to Pennsylvania suppliers [§ 4 of Act 184, amending Title 66 to add § 2805(1)]

RI: Reciprocity is not expressly required, although "foreign electric utilities" may not sell electricity at wholesale or retail within Rhode Island unless "the sale is authorized under its charter or the general or special laws" of Rhode Island or is from generating facilities within the state. § 39-20-4(b)

Comments for LR 455 Phase II - Reciprocity Between States

Reciprocity between states on wholesale and retail transmission service is generally considered a federal issue. The issue of FERC jurisdiction over non-jurisdictional utility transmission brings some complexity to the issue when considering public power. Voluntary participation by a non-jurisdictional utility in the interstate transmission process brings certain reciprocal and comparability obligations (See FERC 888-A clarifications on Orders 888 and 889).

The Phase II study could consider the scenario where there is no federal mandate for customer choice and the voluntary implementation of customer choice by neighboring states brings about a demand for customer choice in some form in Nebraska requiring the consideration of reciprocity between states.

(7) Recovery of Stranded Costs

ALEC: **Full or partial recovery**? - PUC determines amount based on guidelines from state legislature - § 16(A)(1) - ". . . the utilities are entitled to recovery prudently incurred, net, verifiable stranded costs and investments. . . . The amount of recovery will be determined by the state's public utility regulatory body, or other appropriate agency designated by the legislature."

Time frame? - § 16(C)(2)[c] - " . . . not less than three or no more than five years."

Mechanism? - § 16(A)(1) - The state legislature shall determine the just and reasonable recovery mechanisms to determine net stranded costs and investments, including mitigation incentives. However, no transition charge shall cause the total price of electricity to go up for any customer. There is also an offset for the FMV of assets required by a utility during the preceding three years. No recovery for transmission stranded investment.

How do publicly owned utilities recover? - § 16(C)(2) - all utilities subject to same recovery mechanisms.

5. **Who determines**? - § 16 - State legislature and PUC, with guidance from legislature.

CA: **Full or partial recovery**? Article 6, § 367 - PUC will determine amount to be recovered in the transition to deregulated environment. The recoverable transition costs are the net of the negative value of a utility's above market value generation assets against that utility's below market value generation assets. Value is based on appraisal or sale. The transition costs (Competitive Transition Charge or CTC) are included on every retail customer's bill..

Time frame? § 367(a) - As a general rule, costs must be recovered by December 31, 2001.

Mechanism? The PUC-determined stranded costs shall be recovered through a nonbypassable usage-based Competition Transition Charge (CTC) for distribution service. The law prohibits cost shifting in the initial design of the CTC or in the annual adjustment of transition cost levels. The PUC is also to identify and determine categories of recoverable costs for generation-related assets and obligations. Nuclear decommissioning costs are not to be part of the uneconomic costs, but may be recoverable as part of a nonbypassable charge until they have been fully recovered.

NOTE: Article 5.5 - FINANCING OF TRANSITION COSTS: Legislation also authorized California Infrastructure Bank to accelerate debt relief for the utilities' "stranded assets" incurred under the previous regulatory structure. The bank is authorized to issue up to $10 billion in revenue bonds to provide rate relief. State taxpayers have no obligation or financial exposure on the issuance of these bonds.

How do publicly owned utilities recover? If a publicly owned utility elects retail customer choice, it establishes its severance fee or transition charge.

NH: **Full or partial recovery**? [RSA 374-F:3, XII(d) and 374-F:4, V and VI] Stranded costs should be determined on a net basis and should be verifiable, should not include transmission and distribution assets, and should be reconciled to actual electricity market conditions. Only those costs associated with an electric utility's existing production-related facilities and electricity purchase commitments as of May 21, 1996, would be strandable after the point in which retail customers are allowed to choose their generation provider. The PUC suggests that utilities with rates above the regional average will not recover all of their stranded costs.

Time frame? Interim stranded costs recovery charges shall be in effect for 2 years from implementation of utility compliance filings [374-F:4, VI.(a)]; after that, PUC will develop final stranded cost mechanism in company-specific rate cases.

Mechanism? [RSA 374-F:3, XII, AND 374:4, V, VI, VII] Any recovery of stranded costs should be through a nonbypassable, nondiscriminatory, appropriately structured charge that is fair to all customer classes, lawful, constitutional, limited in duration and consistent with the promotion of fully competitive markets. Entry and exist fees are not preferred, and charges should not be applied to wheeling-through transactions. Charges should only apply to customers within a utility's retail service territory, except for costs that have resulted from provisions of wholesale power to another utility. The act defined two mechanisms by which stranded costs could be recovered: (1) It authorizes PUC to allow utilities to collect a stranded cost recovery charge subject to PUC determination in the context of a rate case proceeding, and the burden of proof is borne by utility making such claim [RSA 374:4, V]. (2) ALSO, the PUC is to establish "interim stranded cost recovery charges" on February 28, 1997, for each jurisdictional retail electric company without a formal rate case procedure. [RA 374-F:4, VI (a)]

How do publicly owned utilities recover? Apparently, the same mechanism used by IOUs is to be used by publics.

Who determines? PUC , with FERC approval when appropriate.

PA: **Full or partial recovery**? § 2808(C) - Utilities have an obligation to mitigate these costs to the extent practical. Recoverable expenses include, regulatory assets, NUG contracts and nuclear decommissioning cost. Following review by PUC, they also include other generation costs including investment in nuclear plants, spent fuel disposal, long-term purchase power commitments and retirement costs, and employee transition costs. It should also be designed to fully recover the utility's universal service and energy conservation costs over the program life.

Time frame? § 2808 - COMPETITIVE TRANSITION CHARGE - Recovery will take place over a maximum period of nine years, unless PUC allows an alternate payment period for "good cause", subject to a rate cap.

Mechanism? By means of a nonbypassable charge (CTC) added to the bill of every distribution customer. It also provides for issuance of transition bonds as an additional available mechanism for recovering stranded costs. These bonds will enable refinancing of utility's debt in a more secure fashion at lower interest costs, and will be repaid through an "intangible transition charge" (ITC). The CTC will be reduced by amount of allowable stranded costs refinanced and interest savings realized will be passed directly to customer through rate reduction. Bond maturity may not exceed ten years. PUC must approve and issue order allowing use of these bonds on a case by case basis.

How do publicly owned utilities recover? There is no provision in the Pennsylvania law for the recovery of stranded costs by municipal utilities. Cooperatives are addressed at § 7407.

Who determines? PUC, after a just and reasonable review.

RI: Full or partial recovery? § 39-1-27.4 - The law provides utilities a reasonable opportunity to recover stranded costs that were prudently incurred under the obligation to serve.

Time frame? Except for difficult to estimate nuclear related costs and uneconomic purchased power contracts, which may be recovered until the obligations have been fully satisfied, all stranded costs must be recovered by December 31, 2009, or they will be lost.

Mechanism? The PUC sets a nonbypassable transition charge of 2.8 cents per kwh beginning when retail access begins, through the end of the year 2000. This statutorily set charge will be replaced in 2001 by a PUC-determined charge to recover stranded costs. Any non-regulated power producer may pay all or a part of its customers' transition charges.

How do publicly owned utilities recover? Not discussed.

Who determines? PUC.

Comments for LR 455 Phase II - Recovery of Stranded Costs

Most of the above states provide for some stranded cost recovery, generally based upon market-based costs, within a finite time frame.

The Phase II Study could consider mitigation of strandable wholesale and retail costs and appropriate recovery of legitimate, verifiable costs through a nonbypassable and nondiscriminatory competition transition charge for recovery of stranded consumer-owned assets. The mechanism of recovery should be identified in Phase II. Stranded costs could be calculated by a market valuation which would be determined by the local regulatory authority or public power agency board.

(8) Obligation to Serve

ALEC: No obligation to serve, but there is an obligation to connect. No request by an existing customer constitutes a request to the host utility to serve.

NH: A distribution utility is obligated to connect all customers in its service territory to the distribution system.

PA: § 4 of Act 184, amending Title 66, § 2807, (E) - OBLIGATION TO SERVE: Distribution companies are to continue to be regulated monopolies and providers of last resort, hence, every customer is guaranteed service. During the transition phase where distribution companies are collecting a CTC or ITC or until 100% of its customers have choice, whichever is longer, the Distribution Company has an obligation to serve. At the end of the transition period, the Commission shall promulgate regulations to define the Distribution Company's obligation to serve. If a customer leaves the Distribution Company for an alternate supplier and then returns to the local Distribution Company, they the LDC shall treat the customer exactly as it would any new applicant for energy service.

RI: § 39-1-27.3(f) - The law requires distribution companies to serve power as a "last resort" and to arrange with their wholesale suppliers for a standard power supply offer to customers that no longer qualify for the "standard offer" and cannot obtain service from a "non-regulated power producer." The requirement to make the standard offer extends through 2009.

Comments for LR 455 Phase II - Obligation to Serve

In the above states, in a fully competitive retail competition environment, there is no obligation to serve but there is an obligation to connect. Variations on this theme would be during the transition period to full competition and variations on full retail competition which allow consumers or consumer groups to remain under cost-of-service rate regimes. The supplier of local distribution could be the designated the supplier of last resort with appropriate cost recovery mechanisms for the supplier. Phase II could study the above alternatives as well as cost recovery mechanisms for universal service requirements which involve public policy implications.

(9) Miscellaneous

ALEC: § 23 - Sunset provision - The power of the PSC to regulate terms and conditions of electricity service, including transmission and distribution and rates, will expire 10 years after plan is adopted by state.

Comment: Should Phase II study the concept for a state regulator for distribution services in the retail competitive environment?

CA: Financing of rate reductions for small ratepayers by rate reduction bonds; Utility rates have been frozen at current levels through the end of 2001, except that residential and small commercial customers will receive a 10% rate cut at the beginning of 1998, and an additional 10% rate cut by the year 2002. Industrial users will receive comparable cuts in their rates.

Comment: Should Phase II consider debt financing options as transition elements for retail competition. Phase II could consider rate programs for transition to the retail competition scenario.

Establishment of a Independent System Operator (ISO) and a Power Exchange (PX);

Comment: Phase II could consider the basic need for an ISO and further consider a Nebraska/Public Power ISO as an alternative to other ISO formats. The study could consider alternative methods for improving the wholesale market, including joint dispatch, alliances, and power exchange formats.

NH: Preliminary Plan proposes an ISO and a Power Exchange.

PA: Municipal utilities are not required to participate in retail choice; however, if their choose to participate in retail choice, they must open up their service territories to competition. Act 184, § 4, amending Title 66, § 2805.

Comment: This is the opt-out provision considered several states and discussed earlier.

RI: The law authorizes distribution companies to terminate, in whole or in part, their wholesale power contracts with their suppliers. The termination fees would become a part of the transition charge. § 39-1-27.4

Comment: Phase II could address this methodology because the large dependence of many Nebraska communities on their wholesale supplier and the extensive wholesale customer base of some of the larger public power agencies in the state.

The law provides for a "standard offer" which is equal to the September 30, 1996, rate for that customer and is subject to adjustment at 80% of C.P.I. This offer, which is essentially a rate cap, is available to any customer that does not select power from a "non-regulated power producer."

Comment: Discussed earlier in regards to obligation to service

All sellers of power, whether utilities, brokers or marketers, are lumped into a new unregulated group called "non-regulated power producer.

Comment: This is applicable to the wholesale power activity in the state. If retail competition is considered, then the term becomes applicable to the competitors in that particular market.

Summary: The above comparisons for various elements of state restructuring to retail competition will provide study reference for the Phase II study. As other states select customer choice or federal legislation becomes more predicable, the Phase II focus on the above many issues will become clearer.

B. States That Have Rejected Retail Wheeling

Several states such as Idaho have rejected retail wheeling as not being in the being in the best interest of their consumers at the present time. Such rejections may be deferral of significant action for the present or the result of commission hearings and legislative debate concluding in the decision opposed to opening of their retail systems.

Due to the strong forces at play in the current debate over customer choice or retail wheeling, the issue of federal versus state in the decision to adopt customer choice, and the effect of enacted state restructuring legislation in several states, it would be difficult to forecast how long a state would be willing to retain the position of outright rejection of retail wheeling at some future date.

C. Concerns Addressed by Public Power Testimony

The following testimony offered by APPA in restructuring hearings is included to reflect some of the concerns regarding restructuring from the perspective of public power

1. PRESERVATION OF LOCAL AUTONOMY - Any state initiative should preserve local control and oversight of public power systems.

2. PUBLIC ACCOUNTABILITY - State legislators should provide parity so that all electric providers are subject to the same applicable public records laws and disclosure requirements ("sunshine requirements"), including a state prohibition of the use of confidential rate schedules.

3. STATE MERGER APPROVAL AND MARKET POWER CONCERNS - To prevent regional dominance of local distribution, generation and transmission services markets, State legislators should require the appropriate jurisdictional entity to allow mergers to proceed *only* if they meet a standard which results in "affirmative public benefits", not applying merely a "show no harm" standard. This would prevent abuse of market power by any segment of electric utility industry. State regulatory body should be given clear authority to address antitrust issues and other anti-competitive practices, as well as enforce corrective actions for violations.

4. INDEPENDENT SYSTEM OPERATORS (ISO) - ISOs are a recent concept designed to prevent manipulation and control of the transmission network by transmission owners. State legislators must ensure that ISOs are truly independent and that operational control will be guaranteed to the operator.

5. METER OWNERSHIP - In order to address some of reliability and safety concerns of utilities, States need to preserve ownership and control of meter by the distributing utility. The distributing company should be responsible for billing functions and for maintaining and servicing the meter as well as connecting and disconnecting the service.

6. TELECOMMUNICATIONS - Telecommunications are becoming increasingly important to electric utilities' core business of providing efficient and reliable electric power. Any state restructuring initiatives should ensure that all electric utilities are legally authorized and encouraged to become fully engaged in providing telecommunications services or in facilitating the provision of such services by others.

7. DEBT STRUCTURE DIFFERENCES - State legislators should be cognizant and

sensitive to differing debt structures between public and private utilities when considering restructuring initiatives. Publicly owned utilities have less flexibility to quickly buy down their debt because of fixed timetable for repayment of bonds. IOUs, on the other hand, are in a position to utilize accelerated depreciation methods to better position themselves for competition more quickly.

8. STATE AND LOCAL INITIATIVES - State legislators should review and analyze recent state and local initiatives with regard to electric utility restructuring to learn what has worked and what has not.

9. TERRITORIAL ISSUES - Public power utilities may be unable to compete in a retail competition environment for retail customers outside their services territories due to state laws or local requirements that prevent them from doing so. State legislators need to address this issue when considering restructuring proposals.

10. STRANDED COST RECOVERY - State legislators should provide that legitimate and verifiable stranded costs associated with retail access be fully recovered by all utilities.

11. INTEGRATION OF ENTITIES OTHER THAN IOU'S - State legislators must ensure that non-traditional power providers are not given a "free ride." These non-traditional power providers should have the same obligations and responsibilities as those shouldered by traditional participants, including participation in addressing "societal goals" (such as low income assistance or universal service). Moreover, the non-traditionals should be required to meet certain financial, technical and operational requirements to provide security that certain safeguards are met when a new provider enters a market ("accountability").

12. "PUBLIC GOOD" PROGRAM DEVELOPMENT - State legislators should preserve the ability of local communities to develop innovative programs to ensure universal service, low-income consumer protections, pursue environmentally sound renewable energy sources and promote energy conservation programs.

(a) Low-Income Assistance - The issue of low-income assistance and other public interest goals should be specifically addressed in any restructuring legislation and the burden for funding such programs should be borne by all sectors of the industry, as well as all types of service providers.

(b) Universal Service - It would be a mistake to rely solely on the private sector or "market forces" to achieve the goal of universal service. Programs should be place which provide flexibility for local citizens to develop diverse, innovative and practical solutions to meet the needs of their communities.

(c) Renewable Energy/Energy Efficiency - States should maintain public policies in support of cost-effective energy efficiency and the continued development and commercialization of clean, renewable energy resources. Legislators should not develop a stringent set of rules requiring utilities to produce energy from renewables, but should allow customer-oriented utilities to respond with programs that address customer demands in this area. The key to succeeding in the new market will be understanding the strengths of renewable as an electricity product in that market, and an appreciation of how to market that distinct product.

STRANDED ASSETS, STRANDED BENEFITS AND STRANDED OBLIGATIONS

A. Stranded Assets -

(1) Preface discussion

This section on stranded assets, benefits, and obligations will focus on elements of one of the major evolving issues in the discussion of the Electric Utility Industry restructuring. The section will address both wholesale and retail stranded elements, in part because the FERC orders 888 and 889 address the treatment of both wholesale and retail stranded cost issues.

The general purpose of this Phase I portion of the study is on the effectiveness of the consumer-owned electric utility industry in the state as it currently exists and as it is currently impacted by legislation and regulatory actions currently in place. To this extent, the concept of stranded elements is not perceived to be a major issue for Nebraska at this time as it would be for those states where the federal legislation and regulations have created vulnerability for stranded costs simply because of the "new-found access" to transmission service for distribution agencies not previously available prior to EPAct.

The following stranded assets, benefits, and obligations discussion will create the necessary background needed in Phase I to develop a work plan, schedule and RFP for Phase II work expected to commence about July 1, 1997.

(2) General Definitions of Stranded Elements

(a) **Stranded Assets** - These will be further defined, but generally apply to recovery by the utility from existing and/or departing customers, both wholesale and retail, for investments in assets, costs, and contracts previously approved in a regulated environment, which are or will be made uneconomic in a restructured industry.

(b) **Stranded Benefits** - These are benefits received by the general public or electric customers which are funded by the utilities cost of service, regulated rates, under a monopoly environment. Introduction of competition and restructuring will create an environment where state and local legislative and regulatory agencies may not be able to continue to require the utilities to fund benefits such as energy efficiency, conservation, low-income assistance programs, environmental protection programs and fuel resource diversity from customer rates as currently designed. Other approaches will be needed to facilitate competition while continuing to fund such stranded benefits.

(c) **Stranded Obligations** - These are obligations of electric utilities for the payment of state and local taxes and payments in lieu of taxes and related transfers of funds and services to state and local government. These obligations may be both reduced and shifted from state and local to federal obligations to some extent. As restructuring emerges, alternative revenue transfer mechanisms may be developed

(3) Wholesale Stranded Assets

Wholesale stranded assets are generally assumed to be generation assets and contracts that are made uneconomic or non-competitive as the result of the federal requirement to provide non-discriminatory open-access transmission to customers of the utilities. The competitive market based pricing necessity and the loss of customers through customer choice action is deemed to make some assets uneconomic and FERC orders have included provisions for compensation to the utility for such stranded assets. The extent of the stranding of assets is dependent upon the relationship of the operating and capital costs of the facilities and the short-term and long-term market price levels of electricity, all of which makes the process of stranded asset evaluation complex and to some extent, subjective.

The availability of stranded recovery has been a major factor affecting utility willingness to consider offering or opposing the open access concept in many states. Nebraska has had an open access competitive wholesale market for distribution power agencies for several decades and wholesale stranded cost recovery would not be a major issue under industry restructuring resulting from FERC 888/889, however, if customer choice is introduced into the state, there could be substantial impact on wholesale suppliers. The methods of stranded cost recovery implemented by the FERC and the other states may have a some impact on the regional wholesale energy market in which Nebraska utilities are participants. An excerpt from FERC Orders 888 for Recovering Stranded Costs are provided below for reference purposes:

(a) The Commission will permit a public utility or transmitting utility to seek recovery of wholesale customers by direct assignment.

(b) For stranded costs associated with new wholesale requirements contracts (that is, any wholesale requirements contract executed after July 11, 1994), the regulations will allow recovery of stranded costs only if the contract contains an explicit stranded cost provision that permits recovery.

(c) By "explicit stranded cost provision" the Commission means a provision that identifies the specific amount of stranded cost liability of the customer and a specific method for calculating the stranded cost, charge or rate.

(d) Provisions in requirements contracts executed after July 11, 1994, but before the date on which the final rule is published in the Federal Register, that explicitly reserve the rights to stranded cost recovery pending the outcome of the rule will be considered "explicit stranded cost provisions."

(e) For existing wholesale requirements contracts (that is, any wholesale requirements contract executed on or before July 11, 1994), a utility may not recover stranded costs if recovery is explicitly prohibited by the contract (including associated settlements) or by any power sales or transmission tariff on file with the Commission.

(f) For existing wholesale requirements contracts that do not address stranded costs through an exit fee or other explicit stranded cost provisions, a public utility may seek recovery of stranded costs only as follows:

if the parties to the existing contract renegotiate the contract and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment;

if either or both parties (Nebraska utilities are currently not subject to these articles) seek an amendment to the existing contract under section 205 or 206 of the FPA, before the contract expires, and the Commission accepts or approves it; or,

if the public utility files a request, before the contract expires, to recover stranded costs through a departing generation customer's transmission rates under FPA Sections 205-206 or 211-212(Nebraska utilities may or may not be subject to 211-212 provisions, although this area has not been fully tested or explored).

(g) If the selling utility under an existing wholesale requirements contract is a transmitting utility but not a public utility, and the contract does not address stranded costs, the transmitting utility may seek to recover stranded costs through a surcharge to a departing generation customer's transmission rates under sections 211-212 of the FPA.

(h) For a retail-turned-wholesale customer, a public utility or transmitting utility may file a request to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates under FPA Sections 205-206 or 211-212.

(i) For customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through Commission-jurisdictional rates only if the state regulatory authority had no authority under state law to address stranded costs when retail wheeling is required.

(j) In FERC Order 888-A[13] (rehearing of 888 in early 1997), FERC designated itself as the primary forum for stranded cost claims associated with service to retail customers in territory annexed by a municipality where the facilities of the losing entity are utilized.

(4) Retail Stranded Assets

Similar to wholesale stranded assets, retail stranded assets are the utility's short and long term investments including power plants, transmission and distribution lines, fuel purchase

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13 As discussed in the April 14, 1997 issue of Public Power Weekly, APPA indicated that FERC exceeded its jurisdictional boundaries in setting itself up as the primary forum for stranded cost claims associated with retail customers in territory annexed by a municipality

contracts and wholesale power purchase and sales contracts that would be rendered uneconomical in a competitive market relative to the market price for electricity at the retail level. These would be aggravated by the significant loss of retail market share and long term higher cost generation.

(5) Impact of Stranded Assets on Restructuring

The stranded asset recovery mechanisms are primarily transition issues in the goal to reach effective competition at the wholesale and retail levels. Failure to provide utilities with stranded assets with reasonable cost recovery may create severe economic hardships for utility shareholders and customers, and in particular for consumer-owned utility assets. Most enacted and proposed legislation generally provides a mechanism for stranded asset recovery for a finite period of time or until certain levels of competition have been attained. Additionally, mitigation efforts have been encouraged for utilities with potential stranded assets in the available time interval prior to establishing customer choice so that the amount of stranded asset recovery will be reduced. Restructuring legislation should be drafted to allow sufficient transition time to allow such mitigation.

(6) Disagreement on Stranded Asset Cost Recovery

There are various schools of thought on the concept of stranded asset recovery on both the wholesale and retail stranded costs. From the wholesale perspective, there is not general agreement among utilities, utility groups, and others on the awarding of stranded cost recovery to utilities that did not have wholesale contracts to provide for orderly financing of assets dedicated to wholesale customers kept captive by the withholding of transmission service to the same customers by the utility facing the stranded assets. From the retail stranded cost perspective, most regulators and utilities with stranded retail assets are in favor of recovery. Parties opposed to recovery of retail stranded costs include utilities with minor or no strandable assets, large retail customers and their trade organizations and related "think tanks".

(7) Stranded Assets or Costs Identified in Other States

- Costs incurred by shifting public policy
- Regulatory costs, deferred and fuel suppliers costs
- Post-retirement health-care costs
- Nuclear decommissioning
- Nuclear operation and maintenance expenses
- Above-market payments to power suppliers for purchased power
- Net unrecovered capital costs of all generating plants
- Natural gas pipeline demand charges
- Fuel transportation costs

(8) Magnitude of Stranded Assets

(a) It is too early in the restructuring process to advance a suggestion as to what the magnitude of stranded costs would be nationally. Moody's Investors Service[16] estimated the possible range of total stranded costs for U.S. investor-owned utility companies at $50 billion to $300 billion, with their most likely scenario to be a total of $135 billion. Their report indicates the greatest dollar concentration to be in the Northeast and Western U.S. and could account for more than 40% of the total industry stranded costs. In the 1996 DOE Restructuring Report, regional stranded costs shown below in table 6-2 are estimated based on the difference between the region's average industrial electricity price and the cost of new generation. This amount of stranded assets is estimated at $88 billion, with their NPV of $67 billion. In either case, the amounts shown are subjective,

Table 6-2 Regional Marginal and Average Costs (Cents/kWh) and Stranded Costs in Billions of $

Census Region	Marginal Cost	Average Electricity Price	Difference	Stranded Costs	PV of Stranded Costs	PV as % Share of Rate Base
New England	3.9	9.9	-5.9	16.60	12.7	59.0
Pacific 2	4.1	9.2	-5.0	21.50	16.5	24.0
Middle Atlantic	3.9	9.2	-5.2	12.20	9.3	13.0
Mountain 2	3.8	7.7	-3.9	0.00	0	0.0
South Atlantic	3.9	6.4	-2.5	0.70	2	8.0
East North Central	3.9	6.0	-2.1	7.50	5.8	35.0
West North Central	3.7	5.8	-2.1	0.00	0	0.0
East South Central	3.7	5.3	-1.6	0.00	0	0.0
West South Central	3.8	6.1	-2.2	34.00	2.6	18.0
Mountain 1	3.8	5.5	-1.7	0.00	0	0.0
Pacific 1	3.8	4.2	-0.3	24.00	18.4	54.0
U.S Total				87.80	67.3	17.0

Source: DRI/McGraw Hill, World Energy Service - U.S. Outlook: Fall/Winter 1996 (Lexington, MA, 1996), p.44

dependant upon actions taken prior to retail competition to mitigate the stranded costs and the length of the transition period to competition.

(b) A second perspective for viewing potential stranded costs is the cost to utility stock and bond holders because of the adjustments in credit ratings for utilities with high stranded cost exposure which produced immediate, substantial reduction in share prices in the stock market in 1995.

(c) The above paragraphs on stranded costs pertain to full industry restructuring leading to customer choice. The immediate sub-set of stranded costs for wholesale assets would be substantially less than $135 billion and as of this writing there is no known estimate on what such cost recovery is because the FERC recovery mechanism has not produced any summaries and the transmission access which precipitates stranded costs has

[16] Moody's Investor Services - August 1995 report titled STRANDED COSTS WILL THREATEN CREDIT QUALITY OF U.S. ELECTRICS,

just been initiated in 1996 with the introduction of pro forma tariffs on or before July 8, 1996.

(9) Methods proposed for Recovery or Protection

(a) Methods Established in Enacted Legislation in Other States

California - The California Public Utilities Commission (CPUC) in decisions implementing the state's 1996 legislation for customer choice, has allowed utilities to levy an interim competition transition charge (CTC) on large customers that switch suppliers before retail access takes in effect in the state in 1998. The interim charge will be calculated by adding up the generation-related revenue requirements of the utility's energy cost adjustment clause, the annual energy rate, the generate rate cases in effect, and, Nuclear facilities if applicable. The total will be reduced by an estimate of the market value of forecasted sales. Addition of new customers is expected to reduce the transition costs because they will pay a pro rata CTC and the added demand would be expected to increase the market price of electricity which would reduce an incremental reduction in the amount of transition cost total to recover. The California Assembly Bill 1890 provides that departing customers with demands over 500 kW will pay the interim charge utility customers for switching suppliers until 2002.

Rhode Island - House Bill 8124 establishes the Utility Restructuring Act of 1996 for Rhode Island. The Act provides for Transition Charges. An electric distribution company that buys power at wholesale from a supplier under an all-requirements contract can terminate the contract by paying an appropriate contract-termination fee. The distribution company will be allowed to pass on the cost of the fee to its customers through a transition charge that cannot be bypassed. The termination fee will include the distribution company's share of the wholesale supplier's costs associate with the following:

- Regulatory costs, deferred and fuel suppliers
- Post-retirement health-care costs
- Nuclear decommissioning
- Nuclear operation and maintenance expenses
- Above-market payments to power suppliers for purchased power
- Net unrecovered capital costs of all generating plants
- Natural gas pipeline demand charges

The transition charge can be up to 2.8 cents per kWh for the years 1998-2000 chargeable to retail access customers.

(10) Methods Proposed in Other States considering Restructuring

No states will be mentioned specifically, however, a general observation can be made that most states considering restructuring are including some form of process to reduce or recover stranded costs. Utilities are encouraged to act promptly to reduce exposure to stranded costs with various incentives. Additionally, most states are proposing some form of transition charge to be made to existing and departing customers for a limited time period to compensate the incumbent electric utility for stranded investment/asset costs.

It is important to point out that in most all states except for Nebraska, the debate on stranded costs is focused to a great extent on investor-owned utilities. It is expected that the absorption of stranded cost payment responsibility will ultimately fall on both utility stock holders as well as utility customers. In Nebraska, all electric utilities are consumer-owned and there are not stockholders available to absorb a portion of restructuring stranded costs. The procedures in use for stranded cost recovery in other states, while instructive, may not be considered sufficient and appropriate for consumer-owned utilities in Nebraska. Following is a tabulation of some of the arguments for and against stranded cost recovery in the national debate on the issue:

Arguments for Stranded Cost Recovery

- Existence of "regulatory compact" wherein large high capital cost facilities were approved by state regulatory authorities.
- Utilities should be protected from government policy changes such as safety and environmental program added following initial approval of a utility facility.
- Protection of utility stockholders, many of whom are elderly on fixed income, including current and retired utility employees.
- Recovery will facilitate and accelerate transition to a competitive retail electricity market.
- The extremely high total national cost of facilities exposed to stranding by transition to retail competition.
- Nuclear facilities account for much of the stranded cost exposure. Premature shutdown of nuclear facilities will create a generation capacity shortfall for the U.S.

Arguments against Stranded Cost Recovery

- Stranded cost recovery will reward or protect inefficient producers.
- Recovery will distort competitive market.
- Many strandable facilities were built in the 1970's when there were sufficient "signals" to indicate investment risk.
- Shareholders have already been compensated for the "risk" of utility investments with higher dividends.
- Many industries do not receive compensation for changes in government policy and electric utilities should be no exception.

(11) Potential Wholesale Stranded Assets in Nebraska

(a) This discussion will be limited to wholesale stranded costs resulting from the provisions of EPAct and FERC Order 888 implementing the Act.

(b) The key to effective recovery of stranded costs in general for FERC Order 888 is FERC jurisdiction over the utility seeking cost recovery through wholesale rates administered according to sections 205 or 206 of the Federal Power Act. Because of Nebraska's status as an all public power state, FERC does not have rate jurisdiction over any of the entities in the state Perhaps for special situations, which are not readily apparent at this time, FERC could order stranded cost recovery payments utilizing their authority newly through sections 211 and 212 of the Federal Power Act.

(c) The majority of the wholesale contracts in existence in Nebraska were executed on or before July 11, 1994, and FERC order 888 specifically indicates that a utility may not recover stranded costs if recovery is explicitly prohibited by the contract and or if the contract terms feature a specific termination or notice provisions.

(d) FERC Order 888 provides for the situation of a retail-turned-wholesale customer, in which case a public utility or transmitting utility may file a request to FERC to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates under FPA Sections 205-206 or 211-212. As noted above in the previous paragraph, Nebraska non-jurisdictional utilities would be required to seek a remedy possibly through sections 211-212 of the Federal Power Act or perhaps through state statutes.

(12) Outline of Estimating and Mitigating Stranded Costs[15]

(a) **Estimating Stranded Costs:** The U.S. Department of Energy has prepared a report[16] on stranded costs. Table 6-3 contains alternative ways to compute stranded costs.

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[15] Most of the following material is primarily applicable to states with public utility regulatory commissions for electricity.

[16] DOE/EIA - 0562(96) *"The Changing Structure of the electric Power Industry: An Update"*, 1996 Appendix E - Stranded Costs, pages 143-149

- The bottom-up approach computes the amount of each investment, including contracts, regulatory assets (public power equivalent), social programs, and other stranded liabilities that would be stranded.
- The top-down approach calculates the difference in revenues under a regulatory regime and those likely to accrue with the commencement of competition.
- Ex Ante is before the commencement of transition to competition
- Ex post is after the commencement of transition to competition.
- The FERC methodology for estimating stranded cost obligations is the "revenues lost" approach in hopes of avoiding asset-by-asset reviews to calculate recoverable stranded costs, which may not be the method adopted by various regulatory authorities.

(b) Mitigation Strategies

The National Regulatory Research Institute (NRRI) has developed a classification of 11 strategies outlined in brief as follows[17] for use by states with electric utility regulatory commissions:

Transaction-Related Recovery Devices

Table 6-3 Alternative Ways to Compute Stranded Commitments

	Administrative Valuation		Market Valuation	
	Ex ante	Ex post	Ex ante	Ex post
Bottom-up	Asset-by-asset value projections	Assets valued after restructuring	Assets sold at auction	After-the-fact purchase-price adjustment
Top-down	Projection of regulated rate by customer class	After-the-fact adjustment of regulated prices	Bundles of assets spun off	Deferred valuation of spun-off assets

- Access charge tied directly to continued transmission or distribution service
- Exit fees charged to departing customers, but unrelated to costs incurred on behalf of those customers
- Exit fees charged to departing customers and calculated to recover costs incurred on behalf of those customers
- A share of net generation savings realized by departing customers over time.

17 National Regulatory Research Institute, *The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market - A Briefing Document for State Commissions* (Columbus , OH, November 7, 1994). pp 45-56

Non-Transaction-Related Recovery Devices

- Shifting costs to captive customers
- Charging ratepayers above-cost prices where market exceeds cost
- Accelerated and decelerated depreciation
- Price cap on performance-based rates

Broader Bases

- Entrance fees charged to new generation
- All sellers pay a per-kilowatt-hour tax on generation
- Taxes to include credits for financial write downs or trust funds to subsidize buy out of contracts from nonutility generators

The following additional strategies are listed in six major categories derived from the DOE/EIA report referenced in a previous footnote, many of which may not be applicable to consumer-owned utilities:

Market Actions

- Open Markets Rapidly
- Delay Competition
- Divest Utility Plant
- Mergers
- Market Excess Capacity or Energy

Depreciation Options

- Accelerate Depreciation of Utility Assets
- Transfer Depreciation Reserves
- Accelerated Depreciation Offset with Decelerated Depreciation
- Economic Levelization (opposite of accelerated depreciation)

Ratemaking Actions

- Adjust Utility Returns
- Eliminate Subsidies
- Restructure Rates
- Unbundle Rates
- Allow Rate Flexibility
- Performance Based Ratemaking (PBR)
- Disallow Costs
- Explicitly Shift Cost to Captive Customers
- Exit Fees

- Net Generation Savings
- Access Charge

Utility Cost Reductions

- Reduce Operating Costs
- Reduce Public Policy Program Costs
- Reduce Power Purchase Costs
- Financial Write downs

Tax Measures

- Consumption Tax
- National Tax for Nuclear Plants
- Production Tax
- Tax Reduction
- Tax Deduction

Other Options

- Preserve Retail Franchise
- Eliminate Obligation to Serve (reduce capacity needs)
- Statutorily Authorized Recovery
- Entrance Fee for Returning Customers
- Entrance Fee for New Generation

(13) Summary of Stranded Assets discussion

(a) Nebraska may not have significant wholesale stranded cost exposure under current public law and regulation, in part because of the pre-EPAct open transmission network in the state.

(b) Research on the magnitude of stranded wholesale assets in the region may be useful at some future date if events occur which would reveal an emerging trend of stranded costs unforeseen. [Further research on this section will provide an identification and summary of elements of customer service, operational and planning practices, revenue transfer, bond resolutions, credit ratings, assets and revenue streams that may be affected in Nebraska if retail competition were to be undertaken]

(c) Mandatory customer choice in the state would impact wholesale total requirements contracts and retail service areas as departing retail load would reduce the requirements needed under the contract from the incumbent supplier.

(d) Stranded cost mitigation efforts and the emerging competitive wholesale energy market clearing price and opposition to stranded cost recovery in public policy forums and the courts will probably have significant impact on the ultimate extent of recovery both positive and negative. Some opinion has been expressed that ultimate asset value is determined by selling-off utility generation assets and have further suggested generation sell-offs as an alternative to retail wheeling at the distribution level.

(e) Phase II of LR 455 should consider quantification, mitigation, and recovery of stranded consumer-owned assets when appropriate.

B. Stranded Benefits

General Definition

Stranded benefits could be defined as free or low cost service benefits received by the public which may not be offered in a competitive environment. In many states these program benefits are financed from the public utility rates, in part through the efforts of the public service commission which has rate authority over public utilities. As the restructured electricity industry moves to competition at the retail level, the authority of the public utility commission to set rates and related programs will be diminished, possibly reduced to regulating the rates for wires/delivery services, and in particular to the retail price of electricity which may be provided from outside the state on a market-based basis within the framework of Interstate Commerce (See stranded obligations). The states and local government are not without alternatives however, as funding for benefits can be derived from additional taxes or as charges to portions of the electric business that remain under the regulated umbrella such as the transmission and distribution delivery services.

(1) Stranded Benefits Identified in Other States

- Lifeline or Low Income Rates or Assistance
- Moratorium on service disconnects during extreme hot or cold weather periods
- Subsidized rate classes
- Renewable energy projects
- Universal Service or subsidized line extensions and connections
- No or reduced level account deposits
- Levels of service quality and restoration
- Energy Efficiency
- R&D investment

(2) Magnitude of Stranded Benefits

(a) The magnitude of stranded benefits would vary from state to state and depend greatly upon such programs that are already in place.

(b) In the California restructuring proposal, the cost magnitude of stranded benefits was not published, however, the amount of funds mandated on utilities for the first four years of their restructuring is over $1.6 billion. This amount is a reflection of the magnitude of existing benefit programs funded from electricity rates in California.

(3) Methods proposed for Recovery or Protection

(a) California established a mandated $1.6 billion however has yet to establish how baseline rates and low-income ratepayer assistance will be handled.

(b) Methods Proposed in Other States considering Restructuring have not been quantified in any known reports, however, several state restructuring documents such as New York seek to find a balance between the various state agencies for the funding and coordination of such programs as energy efficiency.

(4) Potential Stranded Benefits in Nebraska

(a) Identification and measurement of the various programs is beyond the scope of the Phase I study and the appropriate consideration of such transition issues would either be in Phase II or other related follow-on activity.

(b) Several elements listed in paragraph (a) above are included in services provided by many of the states public power agencies, and in particular, such items as moratoriums on disconnects during extreme weather service, participation in programs for low-income customers, reliability and efficiency programs, and numerous other community related services unique to consumer-owned systems.

(5) Summary of Stranded Benefits discussion

(a) Ensure that consideration of stranded benefits be included in comprehensive restructuring studies

(b) At the appropriate time, consider developing a special survey to assess the number and magnitude of benefit programs to must be retained and possibly enhanced in transition to a restructured utility industry.

C. Stranded Obligations - General Definition

(1) General Definition

(a) Both consumer-owned and investor-owned electric power systems provide a direct benefit to their communities in the form of obligation for payments and contributions to state and local government. It has been reported that restructuring may impact the financial contributions from electric utilities as general prices and revenues from electricity drop therefore reducing payments sensitive to price level and volume:

- Property and Income Taxes
- Franchise Payments in lieu of taxes
- Gross Receipts Taxes
- Other Taxes and Fees
- Free or Reduced Cost Electrical Service
- Use of Employees

(b) According to American Public Power Association[20] calculated 1994 net payments and contributions for public power systems was approximately 5.8 percent of electric operating revenues. The payments are property taxes, payments in lieu of taxes, and transfers to the general funds. The contributions may also take the form of free or reduced cost services to states and cities which may be considered "obligations" of doing business in the community. (See Section 5 for Nebraska specific discussion)

(2) Stranded Obligations Identified in Other States

(a) Strandable obligations categories in other states are comparable to those listed in the previous paragraph, although in other states, payments are received from both investor-owned and consumer-owned electric utilities.

(b) Nationally, there are over 3,200 consumer-owned, investor-owned and federal electric utilities, with an expanding number of independent power producers contributing to the operation of Federal/State/Local government through tax or in-lieu of tax obligations. The profile of these entities in 1994 according to the U.S. Department of Energy statistics is as follows:

Type	Number	Percent of Sales
Investor-owned	250	76.2
Publicly Owned	2,005	14.4
Co-operatives	939	7.8
Federal	10	1.6
Total	**3,204**	

(3) Magnitude of Stranded (Strandable) Obligations

(a) According to a recent report by Deloite Touche[21], Investor-owned systems

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20 APPA, "PAYMENTS AND CONTRIBUTIONS BY PUBLIC POWER DISTRIBUTION SYSTEMS TO STATE AND LOCAL GOVERNMENTS - March 1996

21 Deloite Touche Report: FEDERAL, STATE, AND LOCAL TAX IMPLICATIONS OF ELECTRIC UTILITY

nationally, contributed approximately 5.9 percent of electric revenue to state and local government for an approximate total of at least $13.4 billion and there are expectations by industry observers that the contributions may be substantially higher.

(b) One estimate is that public power systems alone contribute in excess of $1.2 billion in support of state and local governments. According to the APPA[20], net payments and contributions as a percent of electric operating revenues was a national median of 5.8 percent.

(c) Rural electric distribution borrowers are estimated to have paid more than $381 million in various state and local taxes in 1994[21].

(4) Potential Stranded Obligations in Nebraska

Chapter 5 of this report deals with the transfer payments within the state in detail. Such obligations would be addressed in Phase II transition issues.

(5) Summary of Stranded Obligations discussion

The purpose of this section was to point out the amount and types of payments to state and local governments that would or could be stranded to some extent if appropriate arrangements were not made in the transition process to electric utility restructuring. Detailed discussion of this issue must be reserved for Phase II of the study of consumer-owned utilities in Nebraska as the criteria for determining what elements constitute would be "stranded" has to be developed in a framework of restructuring options.

20 APPA, "PAYMENTS AND CONTRIBUTIONS BY PUBLIC POWER DISTRIBUTION SYSTEMS TO STATE AND LOCAL GOVERNMENTS - March 1996

21 1994 STATISTICAL REPORT RURAL ELECTRIC BORROWERS, USDA, April 1995, Page ix.